- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Questar Gas Company for a General Increase In Rates And Charges	))))	DOCKET NO. 99-057-20 REPORT AND ORDER

ISSUED: August 11, 2000

SHORT TITLE

Questar Gas 1999 General (Distribution Non-Gas) Rate Case

SYNOPSIS

The Commission increases Questar Gas Company's annual revenue requirement by $13,497,484. Of this amount, an interim rate increase of $7,065,000, granted January 25, 2000, is currently reflected in rates. Revenue requirement is based on an adjusted 1999 test year and an allowed rate of return on equity of 11 percent. The Commission also adopts a low-income weatherization proposal.

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APPEARANCES:

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Crossroads Urban Center

I. BACKGROUND AND PROCEDURAL HISTORY

On December 16, 1999, Questar Gas Company ("QGC," "Questar Gas" or the "Company") filed an Application to increase distribution non-gas revenues by $22,227,000 or 11.4 percent. Distribution non-gas revenues recover about 40 percent of the Company's total costs; the remaining 60 percent is recovered through the 191 Gas Cost Balancing Account by means of separate pass-through proceedings.

In Docket No. 98-057-12, the Company filed an Application on November 25, 1998, requesting approval of a gas processing contract with Questar Transportation Services Company ("QTS"), a subsidiary of Questar Pipeline Company ("QPC"), and for authorization to include in the 191 Gas Cost Balancing Account approximately $7.5 million of gas processing costs incurred pursuant to the contract. The Commission issued its Report and Order on December 3, 1999, ruling against pass-through treatment of gas processing costs, and declining to rule on the prudence of the CO_2 gas processing contract. The Commission stated that request for approval of the contract and recovery of costs must be considered either in a general rate case or an abbreviated proceeding as defined by the Utah Supreme Court in *Utah Dept. of Business Reg. v. Public Ser. Comm'n*, 614 P.2d 1242 (Utah 1980).

On December 17, 1999, an Emergency Motion of Questar Gas Company for Interim Rate Relief was submitted, requesting an interim increase in distribution non-gas revenues of $7,065,000, effective January 1, 2000, an amount the Company claims is to recover the costs of obtaining gas (CO_2) processing treatment services necessary for customer safety. The Motion asserts a serious and on-going financial loss from the Commission's refusal to permit pass-through recovery of these costs in Docket No. 98-057-12. The Company asked the Commission to take official notice of the record in that Docket.

On January 4, 2000, a hearing was held to consider the Emergency Motion of Questar Gas Company for Interim Rate Relief. On January 25, 2000, the Commission issued its Order granting an interim rate increase of $7,065,000, effective January 1, 2000, spread on an equal percentage basis to all rate schedules except the Municipal Transportation rate. Within each class, the increase was on a uniform percentage basis to all distribution non-gas volumetric rate components.

On January 4, 2000, intervention was granted to Kern River Gas Transmission Company. On January 26, 2000, intervention was granted to Salt Lake Community Action Program ("SLCAP"), Crossroads Urban Center ("CUC"), and Intermountain Municipal Gas Agency ("IMGA").

On February 14, 2000, the Committee of Consumer Services ("Committee") submitted its Petition for Reconsideration Or Rehearing regarding the Commission's Order Granting an Interim Rate Increase. The Committee argued that the interim increase was not legally proper, factually supported or in the public interest, and the Commission should reconsider its decision, deny the interim rate increase application and order Questar to refund all increased charges since January 1, 2000. On March 1, 2000, a Motion to Strike and Response of Questar Gas Company to Petition for Reconsideration or Rehearing of Committee of Consumer Services was submitted, requesting the Commission to deny the Committee's Petition and reaffirm its January 25, 2000 Order Granting an Interim Rate Increase. The Commission did not respond to either submission, and thereby affirmed its Order Granting an Interim Increase.

On April 4, 2000, intervention was granted to the Large Customer Group (Alliant Aerospace Company, Chemical Lime, Central Valley Water Reclamation District, Chevron Company, ConAgra Beef Company, Cordant Technologies - Thiokol Propulsion, Geneva Steel, Hexcel Corporation, Intermountain Health Care, Springville City, U. S. Gypsum, and Western Electrochemical Company, "LCG"). On May 4, 2000, intervention was granted to Magnesium Corporation of America ("Magcorp"), and the Industrial Gas Users (Kennecott Utah Copper Corporation, BP Amoco, and Westinghouse Electric Company LLC/Western Zirconium Plant, "IGU").

On May 23, 2000, the Motion of Questar Gas Company Requesting Commission's Official Notice of Docket No. 98-057-12 Record was submitted. This motion was supported by the Division of Public Utilities ("Division") and the Committee. The motion was granted.

On June 2, 2000, the Joint Stipulation of Revenue Requirement Issues, an agreement among the Company, the Division, and the Committee on all but four revenue requirement issues, and the CO_2 Stipulation, an agreement between the Company and the Division to include $5 million of gas processing costs in revenue requirement, were submitted. On June 6, the Allocation and Rate Design Stipulation, an agreement among the Company, the Division, the Large Customer Group and the Industrial Gas Users on issues of CO_2 cost recovery and allocation, daily balancing and firm transportation rate design, was submitted.

The Company, the Division, the Committee, the Large Customer Group, MagCorp, Intermountain Municipal Gas Agency, and the Salt Lake Community Action Program/Crossroads Urban Center filed testimony in this proceeding. The Commission held hearings June 5 - 8, 2000. Public witnesses were heard June 7, 2000. On June 23, 2000, the Commission held a hearing to further examine CO_2 plant issues. On June 27, 2000, two late-filed exhibits were submitted by the Company in response to questions of the Commission.

On June 30, 2000, the Company, the Division, the Committee, the Large Customer Group, MagCorp, Intermountain Municipal Gas Agency, and the Salt Lake Community Action Program/Crossroads Urban Center filed post-hearing briefs. On July 5, the Industrial Gas Users filed its post-hearing brief. Parties filed reply briefs July 14, 2000.

II. ADJUSTED 1999 TEST YEAR REVENUE REQUIREMENT

A. COST OF CAPITAL

Using the actual capital structure reported by the Company consisting of 44.96 percent debt and 55.04 percent common equity, with a cost of debt of 8.38 percent and a Commission-determined cost of equity of 11.0 percent, we conclude that a rate of return on investment of 9.82 percent is fair and reasonable.

1. Capital Structure

Questar Gas Company can raise capital in several ways, including issuance of common and preferred stock, issuance of bonds and other debt instruments, and use of retained earnings. The Company, a subsidiary of Questar Corporation, issues its own bonds secured by gas utility assets but does not issue its own stock. As a wholly owned subsidiary of Questar Corporation, it has access to the Corporation's equity capital.

In raising capital, management seeks to minimize capital costs while maintaining the financial integrity of the Company. Financial stability and integrity are important for both stockholders and customers.

The cost of debt and equity depend in part on capital structure. The larger the equity ratio, the lower is financial, or capital-structure, risk. As the firm's equity ratio increases, however, the overall cost of capital rises because equity capital usually commands a higher return than debt. An optimal combination of capital structure and capital costs exists that will minimize the overall cost of capital while maintaining the Company's financial health.

Unlike the cost of debt, the cost of equity capital is not explicit but is competitively determined in the financial markets as the return required to attract investment in the Company's stock.

The Company proposes to use the actual capital structure reported as of December 31, 1999. This shows $225,000,000 in long-term bonds, with adjustments of $1,766,419 in unamortized debt expense and $8,114,770 in unamortized loss on reacquired debt, for a total debt of $215,118,810. The equity portion of the balance sheet shows a par value of $22,974,065 for common stock with associated premium of $ 81,875,000 and unappropriated retained earnings of $158,842,596. Total proprietary capital is $263,391,661. Debt is 44.96 percent of capital structure; equity, 55.04 percent.

The Company and the Division recommend use of the Company's reported actual capital structure to determine overall cost of capital. The two parties provide little testimony on the appropriateness of this capital structure but adjudge it reasonable. As evidence that a financially sound capital structure is necessary, the Company cites the growing risks of competition in the industry. This testimony is not specific to conditions influencing gas utility operations in Utah, however.

The Committee recommends a hypothetical capital structure derived from the group of companies the Commission uses to determine the allowed equity return. The group of six comparable companies used by Company and Division witnesses has an average capital structure of 48.9 percent debt, 2.1 percent preferred stock and 49 percent common equity. The Committee's recommended comparable companies average 47.5 percent debt, 3.0 percent preferred stock and 49.6 percent common stock. Both groups have lower proportions of common equity than does the Company's actual capital structure, and thus more financial risk. All else equal, lower equity ratios are associated with higher allowed rates of return on equity.

Both the Committee and Division witnesses recommend taking financial, or capital-structure, risk into account when determining equity return. The Company believes an adjustment for capital structure is not required because its recommended comparable companies share similar risk ratings, and capital-structure risk was considered in its selection of comparable companies.

We will accept the Company's filed, or actual, capital structure. The Company's actual capital structure has a higher equity ratio than that of the group of companies used to determine return on equity. We are aware the risk assessments performed by financial rating institutions are for Questar Corporation rather than its subsidiary, Questar Gas Company. Testimony indicates that the local distribution company is less risky than is the Corporation as a whole. Moreover, investors recognize financial risk as a factor influencing required return on common equity. For these reasons, we will take financial risk into account as we determine an appropriate rate of return on common equity.

2. Cost of Common Equity

The authorized rate of return on common equity is a key determinant of revenue requirement and thus rates for utility service. Though these rates provide the Company the opportunity to earn this return, there is no implied guarantee it will actually earn the allowed return because the efficiency of Company management and the fortunes of the marketplace intervene. An authorized rate of return does not insulate the Company from business or financial risks, but is set in recognition of them.

a. Positions of Parties

The testimony of the Company, the Division, and the Committee was presented and considered in this Docket. Each party uses financial models to estimate a rate of return on common equity that is fair and reasonable to stockholders and ratepayers. Each follows the principles set forth in the often-cited U. S. Supreme Court Hope and Bluefield cases. Each provides expert testimony which relies on informed judgment about the proper application of financial models. The choice of firms having risk comparable to that of the Company is an issue.

Questar Gas Company.

The Company uses alternative approaches to estimate a reasonable range for the cost of equity capital. With the annual version of the Discounted Cash Flow (DCF) model, six gas distribution companies of risk and size said to be similar to Questar Corporation are analyzed. Both Zacks and Value Line consensus earnings forecasts are used to estimate long-term dividend growth. These growth rates plus spot prices for company stock produce a range of estimates of required return on equity between 11.4 percent and 13.0 percent. The midpoint is 12.2 percent. A comparable earnings analysis of the six companies is also performed. This method relies on Value Line's projected return on common equity for each company, and yields a projected return for 2000 of 12.6 percent, and for a longer-term period, 2002 to 2004, of 13.5 percent.

A Capital Asset Pricing Model (CAPM) analysis provides another estimate. Short-term and long-term versions of this model yield estimates of 10.9 percent and 11.1 percent, respectively. A comparison with historical equity risk premiums in the utility industry is said to verify the reasonableness of the resulting recommendation, which, based on these analyses, is a return on common equity of 12 percent.

Additional evidence is provided to support the recommendation. Alluding to an empirical relationship between the cost of capital and interest rates, the Company focuses on recent Federal Reserve actions raising the federal funds rate and the discount rate. Value Line, the Company states, forecasts 2000 - 2004 earnings of 19 percent to 19.5 percent for its industrial composite, and opines that comparative returns should be in excess of 13.5 percent given its adjustment for overall market risk as measured by the appropriate beta. Though the Company's analysis is updated at the time of hearing for recent changes in interest rates and capital costs, the 12 percent return on equity recommendation is retained.

The Company also sponsors the rebuttal testimony of a securities analyst who states that the Division and Committee recommendations are insufficient to attract capital and provide a reasonable return on equity. The witness asserts that the financial models relied on by other witnesses are not used by investors and should serve only as a starting point. They should be supplemented by a market-driven comparison standard such as indexing utility returns to a five-year rolling average of returns on equity for Standard and Poor's top 400 industrial companies. A negotiated monopoly discount could compensate for the advantage that the exclusive franchise confers on regulated firms. The discounted indexed return would, the witness states, provide investors with similar returns, adjusted for risk, earned by unregulated firms. Without higher authorized returns, the witness opines, investment in utility stocks will diminish.

The Division.

In conjunction with its acceptance of the Company's recommended capital structure, the Division recommends a return on common equity of 11 percent as a fair and reasonable return that will attract the capital a successful company requires. A variety of methods are used to derive and support this conclusion.

Constant and non-constant growth versions of the DCF model are applied to the group of comparable firms recommended by the Company. The Division accepts this group. Its small size, however, concerns the Division because of increased susceptibility to the influence of companies having financial statistics that may not be representative ("outliers"). Such companies can skew the results of an analysis. To account for this effect, the Division advocates the median rather than the mean as a better measure of the central tendency of the group.

According to the Division, the key inputs of the constant-growth DCF model are stock price and growth rate. For price, both spot and three-month averages are tested; no statistical difference between them is observed. The Division uses spot prices. For the growth rate, the Division uses an average of dividend and earnings growth rates. In theory, dividends and earnings are assumed to grow at the same rate, and dividend growth rate is required for applications of the DCF model. But, the Division states, projections of long-term dividend growth rates are rare, and short-term growth rates are volatile and perhaps unsustainable over the long run. The Division maintains that earnings growth is the upper limit for long-term dividend growth and so averages this with dividend growth rates to yield its estimate of the long-term dividend growth rate. Value Line provides forecasts of both earnings and short-term dividend growth rates which are averaged by the Division to produce one estimate of long-term growth. The Division also derives its own estimates, using Value Line data, of earnings and dividend growth rates. These derived growth rates are averaged to produce another estimate of dividend growth. These growth rates then produce a range of DCF estimates for the required return of the six comparable companies of 9.78 percent to 11.54 percent. The midpoint is 10.66 percent.

The Division's non-constant growth DCF model yields a median estimate for the six firms of 11.7 percent. The average of the 11.7 percent and 10.66 estimates is 11.18 percent. The results of both methods suggest a range of 9.78 percent to 11.75 percent, the midpoint of which is 10.77 percent. Both the 11.18 percent and the 10.77 percent estimates are offered as support by the Division for its recommendation of 11 percent.

The Capital Asset Pricing Model (CAPM) is used to check the reasonableness of the 11 percent recommendation. A risk-free rate of 6.14 percent, a market premium of 8 percent, and a beta calculated as the average of the betas of the comparable companies, produces a mean return estimate of 11.01 percent and a median of 10.74 percent. In the Division's view, these estimates support its recommended 11.0 percent. The Division also employs the "Times Interest Earned Ratio" (TIER) to affirm the reasonableness of the recommendation. This ratio is used by financial rating firms like Standard and Poor's to establish bond ratings. The 11 percent recommendation is sufficient to maintain the Company within the range of TIER values required for its current bond rating.

The Committee.

The Committee recommends a range of reasonable returns on common equity of 10.5 percent to 11.5 percent, and a point estimate of 11 percent. This recommendation depends on a hypothetical capital structure formulated as the average for the group of comparable companies the Committee uses in its return analysis. Alternatively, should the Commission accept the Company's actual capital structure, the Committee recommends a lower equity return, 10.5 percent, to compensate for the higher equity component in that capital structure and its correspondingly lower financial risk.

The Committee relies on the DCF, the risk premium and the CAPM methods for estimating return on common equity. The DCF is applied to Questar Corporation, the Value Line group of gas distributors, and the six-company group used by the Company and the Division; the Risk Premium

Method to Moody's Group of gas distributors; and the CAPM to Questar Corporation and the comparable companies. Results are checked against Value Line's projected returns on equity.

An annual, constant growth DCF model is applied to Questar Corporation and two groups of comparable companies. Companies in the first group, the gas utilities selected by Value Line, were eliminated if the DCF analysis produced a return estimate less than the cost of public utility debt, 8.2 percent, or if for other reasons they were outliers. Though this group has a more diverse risk profile than QGC, the Committee adjusts it to reflect these differences. A DCF analysis is also performed using the Company's group of comparable companies. For its DCF analysis, the Committee relies on Value Line's forecasted dividend growth rate and the average five-year historical growth rate in earnings and dividends. In addition, a retention growth rate method provides a check on the reasonableness of the other estimates. For stock prices, a three-month average is used in order to avoid the effects of stock price fluctuations.

With average prices, the estimated return on equity ranges from 9.27 percent to 12.17 percent, depending on the growth rate used. The Company's sample yields a return estimate of 10.24 percent to 12.81 percent. Using Value Line's direct estimate of Questar Corporation's dividend growth along with historical dividend growth, the Committee estimates a return on equity for Questar ranging from 9.1 percent to 9.6 percent.

Though expressing reservations about CAPM, the Committee uses it to check the reasonableness of its return estimates. An historical market premium of 8.05 percent is added to a risk-free rate for 30-year Treasury bonds of 5.9 percent. Together with Standard and Poor's and Value Line betas, these values produce a range for Questar Corporation of 10.72 percent to 11.20 percent, for the Committee's comparable group, 8.54 percent to 10.86 percent, and for the Company's group, 8.70 percent to 10.78 percent. A risk premium, or "bond yield plus risk premium" analysis yields estimates from 10.1 percent to 11.03 percent. The Committee believes this method may be unreliable when the interest rate risk premium is different from the historical premium because the interest rate risk premium associated with bonds can vary over time depending on public perception of future inflation rates. During times of highly fluctuating interest and inflation rates, the Committee states, bonds may appear riskier than stocks.

b. Discussion, Findings and Conclusions

Witnesses' point estimates of required equity return differ in a 100 basis-point range, from 11 percent to 12 percent. The Committee and the Division each temper their recommendations with observations on the Company's proposed, or actual, capital structure.

We have decided to accept the actual capital structure, with the recognition that its higher equity component and lower financial risk have implications for the allowed return on equity decision. In the Company's opinion, capital structure should not affect equity return because it believes financial risk, as accounted for by financial rating firms, is reflected in its selection of comparable companies. Further adjustment for this risk, it asserts, would be double counting. We do not agree. The rating schemes employed by rating firms are too general to adequately account for the effect of financial risk on regulated return on rate base. For example, Value Lines's safety ranking ranges from 1-5; sample companies have a value of 2. Given the range, this implies that a change from one rank to the next is a 20 percent difference in risk. In addition, the risk measure is applied to Questar Corporation, not Questar Gas Company, even though, as the record shows, the subsidiary is not as risky as the parent. We draw the conclusion that these risk measures are insufficient to alleviate the need for further risk assessment. On this basis, we find that capital-structure risk should be considered as we determine an appropriate rate of return on equity.

The Company argues that a higher rate of return is necessary because interest rates recently have risen. But the record does not support the Company's contention. Even if it did, we would not conclude that cost of capital necessarily has increased. No mechanical relationship exists -- the Company agrees -- between interest rates and cost of capital, particularly in the long run. Several variables can affect the relationship between the cost of capital for a particular firm and general interest rates. For example, perceptions of company- or industry-specific risk change over time as do perceptions about inflation. In Docket No. 99-035-10, when this subject was last addressed in a report and order, the Commission relied on testimony stating that no theoretical basis exists to support assertions about a relationship between interest rates and the cost of common equity.

We find that interest rates have not changed significantly since 1995, the time of the last QGC general rate case, Docket No. 95-057-02. The record shows that interest rates were approximately the same at the time testimony in the present Docket was filed as they were when the order in that Docket was issued. In fact, interest rates for the 30-year Treasury bond and the 10-year Treasury bill are lower today. We note, correspondingly, that the Company recommends a lower equity return in the present Docket than it did in the 1995 Docket. Though the record contains Company-sponsored evidence that rates for A-rated utility bonds have increased approximately 60 basis points since the earlier Docket, no relationship between utility bond rates and returns on equity, which adequately considers the effects of relevant variables, has been established on this record.

We are aware that the number of comparable companies in the group the Company relies on has decreased from ten in Docket No. 93-057-01 to six in the current Docket. The smaller the group, the greater the potential influence of the abnormal. This gives rise to a controversy between Division and Company witnesses over the appropriate measure of central tendency. When an outlier can greatly influence the group's mean, or average, results, the Division argues the best of alternatives is to employ the median instead. The Company supports the mean, while the Committee expands the number of firms in the group by using less restrictive selection criteria in order to avoid this small numbers problem.

In past cases, the Commission has opted to eliminate outliers. We continue to believe an adjustment for outliers is appropriate. In the Company's group of comparable companies, one of the six firms has an estimated earnings growth rate almost twice that of the next most rapid, and is the only company in the group which, unlike the Company, has no weather normalization provision in its tariff. For this reason, we give more weight to Division's use of the median and Committee's use of a larger group than to the Company's insistence on the group mean.

Choice by witnesses of key variables in the DCF analysis is invariably a rate case issue. Knowing that movement in stock price directly influences DCF outcomes, the Commission has indicated a preference for a three-month average rather than a spot price. In this Docket, however, the Division testifies it found no statistical difference between the spot price it uses and average prices. Choice of an appropriate growth rate for dividends is another issue. We are generally persuaded that the earnings growth rate is the upper limit for dividend growth rate, and that short-run dividend growth is volatile and perhaps unsustainable. We therefore look to other measures. On this record, an average of dividend and earnings growth rates is appropriate.

Testimony in this Docket shows lower equity return estimates for CAPM analyses than for DCF analyses. The Committee's CAPM estimates for Questar Corporation, the Value Line group of gas distributors, and the Company group range from 8.54 percent to 11.1 percent. The Division's CAPM range is 10.74 percent to 11.01 percent. The Company's range is 10.9 percent to 11.1 percent. These estimates indicate that an equity award of 11 percent is reasonable.

We are less confident of risk premium and comparable earnings approaches and accord them less weight in our equity return decision. For example, Value Line projects an average return on common equity for QGC's six comparable companies of 12.6 percent for the year 2000 and 13.5 percent for 2002 - 2004. Projected market returns for Value Line's industrial composite influence us even less because a premium for unregulated versus regulated firms has not been established on the record. The Committee's risk premium estimates are in a range of 10.09 percent to 11.03 percent.

Based on our consideration of the testimony and evidence, we determine that the allowed rate of return on common equity should be 11 percent. This is well within the range of reasonable returns of 10.5 to 12 percent produced on the record. In reaching this decision, we depend on the results of financial-model analyses. As in past dockets, we rely most on the DCF. We dismiss the contention that these models are inadequate and will investigate new methods when tangible evidence is presented that the utility is unable to attract equity capital. Until then, we will continue to rely on financial models and other relevant evidence. Capital structure or financial risk also weighs in favor of a lower return award than requested by the Company. We note the Division's examination of the Times Interest Earned Ratio as evidence the award of 11 percent will maintain the Company's current bond rating.

The allowed equity return, combined with the actual capital structure recommended by the Company and the Division, produces a rate of return on rate base of 9.82 percent. This overall rate of return is fair and reasonable. It will allow the Company to raise capital in the market on reasonable terms.

B. UNDISPUTED ISSUES

Utah non-gas distribution revenue requirement is determined using a computer model developed as a result of the Commission's order in Docket No. 93-057-01. This model begins with the Company's unadjusted results of operations for the twelve months of the test year, presented in the detail of the FERC accounts. Adjustments are made to the system results. The adjusted system results of operations are then apportioned between the Wyoming and Utah jurisdictions, with Utah responsible for roughly 96 percent. The Utah adjusted results are then separated into those accounts relevant to the recovery of gas costs in pass-through proceedings, and those relevant to the determination of distribution non-gas revenue requirement in general rate proceedings. The values associated with the adjustments in the following sections are system values, and thus do not correspond directly to changes in Utah distribution non-gas revenue requirement. The incremental and cumulative effect on Utah distribution non-gas revenue requirement of the adjustments are presented in each of Sections B through E, below.

Representatives of the Division and Committee have analyzed the Company's results of operations for 1999, the test year for this Docket. A number of proposed adjustments to revenue requirement are undisputed. It is our practice to accept adjustments, whether proposed by the Applicant or the parties, which all agree should be adopted. Each undisputed adjustment is briefly described in this Section.

1. WEXPRO Production Plant

This adjustment, rising from Section 5(b) of Exhibit E of the Wexpro Agreement, requires that the production plant component in each Questar Gas rate base plant account be reduced by 6.3 percent. According to the agreement, Wexpro adds 6.3 percent of Questar Gas's production plant to the Wexpro investment when calculating the Wexpro service fee charged to Questar Gas. The agreement also removes 6.3 percent of the accumulated depreciation, depletion and amortization associated with production plant. It reduces rate base by $1,668,118.

2. Underground Storage

Pursuant to the final order in Docket No. 93-057-01, Account 164, Gas Stored Underground - Current, is to be accounted for in the Company's pass-through cases and excluded from test-year rate base in distribution non-gas rate cases. This is accomplished by allowing a return on the actual average balance in this account to be entered as a gas cost. An adjustment removes the total balance of Account 164, or $14,016,185, from rate base.

3. Banked Vacations

Questar Gas employees can accrue up to one year's worth of vacation and carry it forward. Because the allowed vacation in each year is included in the labor overhead of that year, the "banked" vacation represents compensation for work performed but not yet paid for. Consistent with the Commission's order in Docket No. 93-057-01, the adjustment is calculated as the projected 13-month average banked vacation for the period ending December 31, 1999. This adjustment reduces rate base by $858,413.

4. Sale of Company Property

The Company sold certain utility properties both prior to and during the test year. Net investment in the properties was not removed from test-year rate base in the Company's filing and depreciation expense on them was included in test-year expense. An annualization adjustment removes net investment of $2,135,759 and depreciation expense of $81,247 for these properties from the test year.

5. Forecasted Revenues

Test year revenues, including distribution non-gas, supplier non-gas, gas commodity, and other revenues, as well as gas supply expenses, are adjusted by the Company to forecast levels. For the GS-1 and GSS Schedules in particular, the Company adjusts volumetric sales for test-year temperatures that were warmer than usual, stating temperature-normalized sales volumes and revenues on a calendar-month basis, and bills the temperature-adjusted test-year sales volumes at rates that became effective December 1, 1999. Normal temperatures are based on a thirty-year period ending December 31, 1990. Also, large customers who changed rate classes during the test year are billed on their current rate schedule throughout the test period. Included in this adjustment is an increase in distribution non-gas revenues of $3,823,902. In addition, the tariff distribution non-gas revenues are subject to adjustment in C.12, below, and revenues from the New Premise Fees and Service Initiation Fees are subject to adjustment in C.11, below.

6. Oak City Revenues

Due to problems during the service sign-up of customers, revenues from the Extension Area Charge in Oak City, Utah were not collected. This adjustment recognizes that these charges should have been collected, and increases revenues by $12,240.

7. Labor Annualization

Questar Gas normally specifies merit increases for employees effective September 1 of each year. This adjustment annualizes the effect of the merit increase back to the beginning of the test year, and increases system labor and overhead costs by $1,610,062.

8. Phantom Stock

Consistent with the Commission's Order in Docket No. 93-057-01, an adjustment has been made to increase the expense for the 12-months ended September 1999 by removing all entries related to "phantom stock" for Questar Gas and Questar Regulated Services. The adjustment reflects actual Distrigas allocation percentages (discussed in Section D.17) used to allocate phantom stock charges from Questar Corporation to Questar Gas, and decreases expenses by $406,351.

9. Uncontested Advertising

In the final order for Docket 93-057-01, the Commission delimited the types of advertising expenses recoverable in rates. Following that order, this adjustment removes undisputed amounts of advertising determined by the parties unrecoverable from utility ratepayers, and decreases expense by $613,370.

10. Olympic Contributions

Questar Gas is an official supplier of the Salt Lake City 2002 Olympics. This adjustment removes $10,039 in expenses or contributions made by Questar Gas or allocated to Questar Gas by an affiliate.

11. Uncontested Dues & Donations

This adjustment reflects that portion of industry association membership dues and donations for lobbying and political organizations during the test year which were identified and removed by the Company, and uncontested by the Division and the Committee. The adjustments include costs that were charged directly to Questar Gas from Questar Corporation or indirectly through Questar InfoCom, Questar Pipeline and Questar Regulated Services. It reduces expenses by $113,164.

12. Jazz/Buzz/Grizz Tickets

This adjustment removes that portion of the Jazz/Buzz/Grizz tickets, allocated directly to Questar Gas from Questar Corporation or indirectly through affiliates, that were related to marketing, reducing expenses by $33,566. A second portion of Jazz/Buzz/Grizz tickets, related to an employee recognition program, is addressed in Section II D.

13. Affiliate Rate of Return

Certain services provided by Questar Corporation and affiliates are billed to Questar Gas at cost-of-service rates that include a return on investment tied to Questar Gas's currently authorized return on equity. This adjustment reduces those expenses to reflect the rate of return on equity authorized in this Report and Order. Additionally, it reduces expenses for corporate aircraft charged to Questar Gas. The need for and method of calculating the adjustment are undisputed. The adjustment decreases expenses by $251,142.

14. Questar Energy Services

Prior to this test year, Questar Energy Services was transferred from the Market Resources Group of Questar Corporation to Questar Regulated Services. Questar Energy Services is an unregulated marketing organization that offers products and services to customers in Utah and Wyoming. During the test year, Questar Energy Services was not included in the Distrigas portion of the allocation of Questar Regulated Services costs among affiliates. This adjustment is the amount of Questar Regulated Services expenses allocated to Questar Gas that should have been allocated to Questar Energy Services during the test year. This adjustment reduces expenses by $166,431.

15. Credit Card Expense

In July 1999, Questar Gas began accepting credit-card payments. The Company pays a fee to credit card companies when it accepts payments in this way. An adjustment annualizes credit-card expenses for the test year. It increases expenses by $16,483.

16. Questar InfoCom Y2K

During 1999, Questar Gas incurred charges of about $1,449,000 from Questar InfoCom for projects related to Y2K preparation and program modifications. This adjustment amortizes these expenses over a three-year period, allowing recovery of about $483,000 annually. It reduces expenses by $966,363.

17. SCT Banner

Prior to the test year, Questar Gas purchased a computer software system, SCT Banner, which it expected to use as a customer information and billing system. During the test year, the Company determined that this program would not be used. This adjustment removes the 13-month average investment of $322,000 from rate base, and removes $1,555,823 of depreciation expense related to writing off the system. It also removes $218,000 of the 1999 annual maintenance costs associated with this system.

18. Gathering

The Commission's final orders in Docket Nos. 95-057-30, 96-057-12 and 97-057-11 require removal of expenses for gathering Company-owned gas production from the gas-cost portion of rates for recovery through the distribution non-gas portion. This adjustment annualizes these expenses into the test year. When the Company calculated test-year revenues using the weather-normalized test-year volumes at rates in effect on December 1, 1999, the annual revenues related to gathering were fully included. The expense annualization is needed to match the revenues. This adjustment increases gathering expenses by $7,703,278.

19. Other Expenses

This adjustment decreases expenses by $9,249 for removal from the test year of two out-of-period expenses that were included in the Company's reported results of operations. The first expense is for temporary one-time charges for rental property sold by Questar Gas to Nu Skin International until Questar Gas was able to move into other facilities in January 1999. Its removal decreases expense by $14,796. Second, Questar Gas underbilled Universal Resources Corporation for premises that it leases at Questar Gas' storage building. This entry represents additional rental income received for the period September 1 to December 31, 1998. Its removal increases expense by $5,547.

C. UNCONTESTED ISSUES IN STIPULATION

The Company, the Division, and the Committee submitted the Joint Stipulation on Revenue Requirement Issues on June 2, 2000. On the first day of hearings, June 5, 2000, these parties each provided a witness to support the Stipulation. The Company moved the Commission to approve the Stipulation on the basis of their testimony and supporting record evidence. On June 6, 2000, we approved the motion and accepted the Stipulation, which is attached to this Report and Order as Appendix 2.

The Stipulation separates revenue requirement issues into uncontested, stipulated, or contested groups. We begin with the uncontested issues. Testimony indicates parties to the Stipulation would not have contested them even in the absence of this Stipulation.

1. Co-op Advertising

By Commission rule, promotional advertising expense cannot be recovered from ratepayers. This adjustment removes co-op advertising expenses of $7,070, as promotional advertising, from the test year.

2. Professional Gas Cooking Advertising

This adjustment removes a professional gas cooking advertising campaign of $14,400, as promotional advertising, from the test year.

3. Pacific Coast Gas Association Dues

This adjustment removes $18,722 in dues paid to the Pacific Coast Gas Association for the year 2000. This payment, related to a period beyond the test year, is a duplicate payment of dues during the test year. 1999 dues were paid by Questar Corporation, billed to Questar Regulated Services, and allocated to Questar Gas in April 1999. Subsequently, 2000 dues were paid by Questar Regulated Services and allocated to Questar Gas in December 1999.

4. REACH Program Payments

The Residential Energy Assistance through Community Help (REACH) program is administered by the American Red Cross. Voluntary contributions from Questar Gas customers are placed in a fund that the Red Cross distributes to qualifying individuals to help them pay their Questar Gas bills. Initially, the Division proposed to disallow a payment from Questar Gas to the American Red Cross as a charitable contribution. The proposed adjustment was subsequently withdrawn because the payment helps to cover REACH program administrative costs. The Commission has previously approved recovery of these costs in rates.

5. Business Development Activities

During the test year the Company incurred expenses for business development in Ireland. In addition, a consultant was retained to assist in the new business development activities of Questar Pipeline and other non-regulated affiliates. These costs were allocated to Questar Gas by Questar Regulated Services. This adjustment removes $102,643 of expenses from the test year.

6. Out-Of-Period Expenses

This adjustment removes several expense items that are out-of-period. The first is a $32,004 payment, termed DocuCorp International, for an annual license fee that should have been paid in 1998, but was not paid until June 1999. The 1999 annual license fee was also paid in 1999, resulting in double payment in the test year. Second, several charges from Questar Regulated Services which when allocated to Questar Gas total $56,702, are identified as out-of-period charges. Third, two charges from Questar Corporation, when allocated to Questar Gas total $4,867, are identified as out-of-period charges. One is a payment for travel bill made in 1998 to American Express. The other is a payment for Industrial Relations Council Dues for 2000, when the test year already includes the payment of such dues for 1999. This adjustment removes $93,573 in total for expenses that have been identified as relating to periods outside of the test year.

7. Other Affiliate Charges

This adjustment removes other charges from affiliates that should not be recovered from ratepayers of the regulated distribution company. These include expenses associated with Southern Trails which, when allocated from Questar Regulated Services to Questar Gas, total $4,116, and charges from Questar Corporation which, when allocated to Questar Gas, total $24,906. The adjustment removes $29,022 in expenses associated with affiliate activities from the test year.

8. Golf & Skiing Expenses

This adjustment removes from the test year $1,409 in expenses related to customer golfing and skiing events.

9. Lobbying

This adjustment removes $80,054 of expenses for lobbying and other political activities incurred during the test year. It includes costs that were charged directly to Questar Gas from Questar Corporation or indirectly by means of the Distrigas allocation formula from Questar InfoCom, Questar Pipeline and Questar Regulated Services.

10. State Income Tax

This adjustment removes an incremental tax benefit allocated to Questar Gas as a result of Questar Corporation's consolidated Utah tax return, and increases Questar Gas expense by $49,232. For state income tax purposes, the Utah portion of consolidated business income is computed based upon the ratio of assets, payroll and total sales in Utah to the total of the consolidated Company, including affiliates. This adjustment prevents ratepayers from paying additional taxes arising as a result of affiliate earnings or, as is the case here, paying less in taxes as a result of affiliates' losses.

11. Other Revenue

In the Company's forecasted revenues adjustment, B.5 above, the Company increased the actual Utah amounts recorded on its books for the Services Initiation Fees by $6,424 and decreased the New Premises Fees by $347,880. This adjustment reverses that portion of the Company's revenue adjustment by restoring actual for estimated revenues. It also includes an increase in Utah revenues of $37,400 associated with an undisputed increase in the fees for processing bad checks, discussed in Section II.A.1 below. The total of this adjustment increases revenues by $378,856.

12. Tariff Distribution Non-Gas Revenue

In the Company's revenue adjustment, B.5 above, the Company included forecasts of distribution non-gas revenues for tariffed rate schedules. This adjustment reverses portions of the Company's revenue adjustment to include actual test-year billing adjustments including minimum bills for certain individual customers that did not meet their contract-demand requirements. The adjustment increases tariffed distribution non-gas revenue by $240,639.

13. Equal Payment Plan

In its direct testimony, the Committee proposed to remove from rate base the test-year average Equal Payment Plan balance on the belief that the balance was not adequately represented in the lead-lag study. This study had been used in Docket No. 93-057-02 but was later revised by the Company. Also revised was the calculation of the Accounts Receivable lag. The revisions were filed in Docket 95-057-02 and in the present Docket. The method for calculating the Accounts Receivable lag now captures the effect of the Equal Payment Plan. Consequently, the proposed adjustment was withdrawn.

14. Prior Period Clearing Account Adjustment

To cover warehouse overhead costs, the Company adds ten percent to the cost of materials issued. In 1998, this resulted in over-recovery of stores expense, and a subsequent accounting entry reducing expenses by $320,000 was made during the 1999 test year. This adjustment removes the expense decrease associated with a prior period, thereby increasing expense for the test year.

15. Gross Receipts Tax

Payments of regulatory utility fees in Utah, Wyoming and Idaho of $1,401,049 were not recorded in test-year expenses. This adjustment increases expenses in the test year to include them.

16. Miscellaneous Corrections

Legal expenses of $79,064 for gas-supply litigation involving Jack J. Grynberg were included in test-year expenses. These expenses are properly recorded in the 191 Account and recovered through gas costs. Second, charges from Questar InfoCom of $245,735 for maintenance of the Appliance Financing program were included in the test year but should have been charged to Questar Energy Services, which now administers the program. This adjustment removes these two expenses from the test year.

D. STIPULATION OF CERTAIN REVENUE REQUIREMENT ISSUES

The Joint Stipulation on Revenue Requirement Issues, which we adopted on June 6, 2000, neither resolves issues individually nor is precedent for future regulatory treatment of them. The Company, the Division, and the Committee, as parties to the Stipulation, testify that the stipulated outcome for the set of issues as a whole is reasonable. Each party reaches this conclusion in its own way, which, while protecting the confidentiality of negotiations, is generally stated on the record. The Company testifies that it considered likely outcomes for each issue and a reasonable resolution of them in total, that is, without requiring a specific decision for each issue. The Division states that it did not compromise on adjustments concerning which the Commission had previously ruled. Most of its proposed adjustments, it states, were unchanged as a result of stipulation. The Committee believes the Stipulation is close to what the Commission would have ordered had each issue been separately litigated, is beneficial because it narrows the focus of the proceeding to adjustments which are the real basis of the Company's case for a rate increase, and allows the customers the Committee represents to know why the Stipulation should be supported.

The Stipulation states that: (1) the parties have not been able to reach an issue-by-issue agreement on the stipulated issues presented in this Section, (2) the parties have concurred on the aggregate effect that an overall resolution of these issues is to have on the Company's revenue deficiency, (3) the Stipulation shall not constitute an acknowledgment by any party of the validity or invalidity of any principle of ratemaking, and (4) the Stipulation shall not be introduced or used as evidence for any other purpose in a future proceeding by any party to the Stipulation.

In this Section, the positions taken by the Division and Committee are presented. The Company takes no position with respect to the specifics of these stipulated issues. The Stipulation, based on the Company's proposed rate of return on rate base, decreases by $1.55 million the increase in distribution non-gas revenue requirement relative to the Company's position on all issues as of May 15, 2000.

1. Advertising/In-Flight Audios

The Division and Committee propose an adjustment to remove $14,260 in corporate financial advertising expenses allocated to Questar Gas for "In-flight Audio" interviews with Questar's vice-president of public affairs aired on airlines while in flight. These advertisements promote Questar Corporation stock and are directed to potential investors. The Committee's initial adjustment was $11,024, but it would adopt the Division's higher figure for purposes of stipulation.

2. Advertising/Smart Money

For purposes of stipulation and settlement, the Committee would withdraw a proposed adjustment to remove $11,710 in Smart Money advertising expenses.

3. Advertising/Clean Air

The Division would support an adjustment to remove $11,041 in expenses for public interest advertising related to clean air.

4. Advertising/1999 Fact Sheet

The Committee proposed an adjustment to remove $82,906 in corporate financial advertising expenses, allocated to Questar Gas, for a 1999 Fact Sheet placed in three magazines detailing financial highlights and other information for investors. In reaching the stipulation, the adjustment would be reduced to $41,453.

5. Dues & Donations/American Gas Association

Initially, the Committee supported an adjustment to remove $53,063 in expenses associated with the portion of the American Gas Association dues related to governmental relations, which the Committee regards as lobbying activities. For purposes of stipulation, $5,306 would be disallowed.

6. Dues & Donations/Homebuilders

An adjustment, proposed by the Division and Committee, would remove $7,808 in expenses for contributions to economic development and homebuilder's associations.

7. Dues & Donations/Economic Development Corporation

An adjustment, proposed by the Division and Committee, would remove $40,000 in expenses for Questar Gas' support of the Economic Development Corporation of Utah.

8. Questar Corporation Incentive Compensation

Questar Corporation allocates a share of incentive plan payouts to Questar Gas, which proposes to increase this share by $22,655 based on the five-year average payout associated with operating goals. The test-year amount, however, was zero. The Division and Committee would remove this adjustment, thereby excluding from regulated revenue requirement the incentive plan expenses allocated from Questar Corporation.

9. Jazz/Buzz/Grizz Tickets

The Division proposes an adjustment to remove $20,665 in expenses for Jazz/Buzz/Grizz tickets given to Questar Gas employees for exemplary performance. For purposes of stipulation, the Division would withdraw the adjustment.

10. Company Store/Paragon Press

The Division and Committee propose an adjustment to remove $39,658 in expenses, the allocated portion of the cost of producing a book on the history of the Company.

11. Lead-Lag Study Update

The original and revised filings by the Company in this Docket include a calculation of cash working capital using a Docket No. 95-057-02 lead-lag study. That study, based on calendar year 1994, provided a net lag of -1.346 days. In the Company's rebuttal filing, a revised lead-lag study based on calendar year 1999 is used. It provides a net lag of 0.115 days. The difference is due to an increase in the lag days for higher accounts receivable balances caused by residential customers paying more slowly than in 1994. Also contributing to the change were decreases in the lead time associated with gas purchases and other accounts payable. The revised study includes the full impact of the Equal Payment Plan. The Division reviews the 1994 and 1999 lead-lag studies and finds them consistent with Commission Orders. The Division and Committee would support the use of 0.115 net lag days to calculate cash working capital.

12. Prepaid Pension Plan

Prepaid pension expense is a balance-sheet account the Company uses to record the difference between cash contributions to the pension plan and pension expense recorded on the income statement. As of December 31, 1999, this account had a debit balance of $2,399,941, reflecting the amount cumulative cash contributions to the pension plan exceed recorded pension expense. In 1987, SFAS 87 changed the way pension expense is to be recorded. SFAS 87 seeks to properly record the cost of pension benefits over the expected work-life of employees using current interest rates. It offsets the cost with returns earned by assets in the pension fund.

The pension plan actuary has continued to calculate required cash contributions to the plan using Internal Revenue Service and Department of Labor requirements. Since 1987, pension expense calculated pursuant to SFAS 87 has differed each year from the cash contributions. In its direct testimony, the Division proposes to reduce rate base by the $2,399,941 balance in this account. To reach stipulation, the Division would support an adjustment to remove $233,680 from rate base.

13. Gain On Sale Of Property

During the test year, the Company sold two former business office sites realizing a gain of $895,278 for the "Salt Lake South" property and $203,958 for the "Price" property. The total gain, $1,099,236, is recorded by the Company in Account 421, a below-the-line account. The Division proposes an adjustment, for rate-making purposes, to amortize the gain over three years, and thereby to increase test-year revenues by $336,412. Initially, the Committee proposed to include the entire gain in test-year revenues. For purpose of stipulation, it would support including half, or $549,618.

14. Contributions In Aid Of Construction

During the test year, a $574,356 contribution in aid of construction was received from a large customer. In the Company's original filing, the entire amount was removed as a one-time, non-recurring item. The Division would propose an adjustment to amortize this contribution over three years, and thereby include $191,452 in test-year revenues.

15. Questar Gas Incentive Compensation

Questar Gas has two incentive compensation programs, the Annual Management Incentive Plan (AMIP) for management and the Performance Incentive Plan for Employees (PIPE) for other employees. The plans have the same financial and operating goals. During the test year there were no payouts in the AMIP plan. Payouts for the PIPE plan were 1.56 percent, all related to operating goals.

Proposed adjustments remove the accrual for PIPE and AMIP plans from the test year and substitute the appropriate payout amounts for the plans in the test year. The Company proposes to include $1,296,280, based on a five-year average of plan payouts related to operating goals; the Division, $681,280, based on recognizing only a portion of the customer service goal; and the Committee, $760,000, based on the 1999 percentage of operating goals and payroll base, but excluding overheads from the calculation. The net adjustment the Company proposes is an increase in expenses for the test year of $110,280; the Division, a net decrease of $504,720; and the Committee, a net decrease of $426,000.

The Division and Committee would remove from expenses the actual 1999 accrual of $1,186,380. Applying the 1.56 percent payout of the PIPE plan to test-year base payroll, with an overhead rate of 19.45 percent, yields a total test-year incentive plan payout, as proposed by the Company, of $907,405. For purposes of stipulation, the Division and Committee would accept this amount. Thus the net adjustment which the Division and Committee would support is a $278,975 decrease in expense.

16. Uncollectible Accounts

The Company proposed an adjustment to reduce uncollectible expense by $4,181, the actual write-off during the test year and an amount less than that accrued to expense during the test year. In its direct testimony, the Division proposed an adjustment decreasing uncollectible expense by $529,134 based on a three-year average, 1995-1997, of the ratio of net writeoffs to average accounts receivable. This ratio was fairly consistent during that period at approximately 6.3 percent. 1998 and 1999 would be excluded by the Division because at 7.9 and 8.7 percent, respectively, the ratios of net writeoffs to average accounts receivable depart from the more consistent ratios of prior years. The Division also included $300,000 in its calculation of net write-offs, an amount the Company indicates is attributable to the effect of increased bankruptcies on uncollectible expense during 1998 and 1999. In its direct testimony, the Committee proposes an adjustment decreasing uncollectible expense by $544,675 based on a five-year average, 1995-1999, of the ratio of net writeoffs to average accounts receivable. For purposes of stipulation, the Division and Committee would support an adjustment decreasing uncollectible expense by $290,015, based on a three year average, 1997-1999, of the ratio of net writeoffs to average accounts receivable.

17. Distrigas Allocation Update

The Distrigas formula allocates Questar Corporation common costs to subsidiaries. The Division recommends updating the Distrigas formula for 1999 operating results in order to reflect test-year changes. For purposes of stipulation, the Division and Committee would support an adjustment to reduce expenses by $146,471.

18. Gas Research Institute

The Company proposes an adjustment to increase expense in the test period by $215,932 to recover, in distribution non-gas rates, Gas Research Institute ("GRI") funding of research and development (R&D). In the past, support for this R&D has come through payment of a FERC-approved charge which is included in interstate pipeline rates. The charge, about $2 million per year, has been collected from Questar Gas's sales customers. The FERC has approved an agreement in a recent GRI proceeding to phase out the mandatory pipeline charge in yearly increments through 2004.

Corresponding to the decline in the FERC surcharge, the Company proposes to reduce supplier non-gas costs and to increase distribution non-gas costs. Total R&D costs recovered from customers would be unchanged. The 1999 reduction in the FERC surcharge is $215,932, an amount reflected in rates for Questar Gas's Utah customers effective December 1, 1999. The Division and Committee propose to exclude any GRI amounts from test-year expenses, but for purposes of stipulation would withdraw the adjustment. This issue is addressed in Paragraph 11 of the Stipulation.

19. Reserve Accrual

The Division proposes an adjustment to decrease expenses by $703,280 for a five-year amortization of $879,100 in a reserve accrual for the Company's self-insurance program. The Company agrees with the proposal. In its direct testimony the Committee recommends exclusion of the entire amount from the test year, a further expense decrease of $175,820. For purposes of stipulation, the Committee would withdraw its adjustment.

E. CO_2 GAS PROCESSING COSTS

In Docket No. 98-057-12, the Company applied, among other things, for approval of its contract with an unregulated affiliate, Questar Transportation Services Company ("QTS"), for removal of carbon dioxide from central Utah "coal seam" gas which, transported by its affiliate, Questar Pipeline Company ("QPC"), was entering its distribution system. The Company contends that, by early 1998 when the likelihood of continuing increases in the volume of this gas became apparent, it had no acceptable alternative but to process the gas because it has a lower BTU content than the distribution system requires and will not burn safely in customer appliances. A decision regarding the contract was not reached in that Docket, however. On page 8, the December 3, 1999 Report and Order explains: "While QGC presents some evidence intended to address the prudence of entering into the contract and the reasonableness of its terms, the Division and the Committee maintain that these proceedings are not a prudence review and the Commission should not address the reasonableness of the terms. The prudence and reasonableness issues are purposely not resolved by this Order." As stated in the Order's Synopsis, a "[r]equest for approval of the contract and recovery of costs must be considered either in a general rate case or an 'abbreviated proceeding' as defined by the Utah Supreme Court in *Utah Dept. of Business Reg. v. Public Ser. Comm'n*, 614 P.2d 1242 (Utah 1980)."

The Company's Application in the present Docket seeks recovery of $7, 343,000 of gas processing costs incurred pursuant to the contract with QTS, but, unlike the preceding Docket, does not seek approval of the contract. In filed direct testimony, the Division recommends disallowance of half the processing costs while the Committee opposes recovery of any. In the Committee's view, the decision to enter the contract is imprudent and the processing costs are not reasonably the responsibility of QGC customers. The Large Customer Group states in direct testimony that it does not support recovery of processing costs from ratepayers.

Except for the Committee and the Large Customer Group, these positions changed with the filing prior to hearing, on June 2, 2000, of a CO_2 Stipulation by the Company and the Division resolving between them the issues of cost recovery and ratemaking treatment of gas processing costs. In the CO_2 Stipulation, which is attached as Appendix 3, the Company and the Division "agree and stipulate that CO_2 processing contract costs in the amount of $5 million for the Utah jurisdiction should be included in the revenue requirement in this case." The Committee and other intervenors are not party to the Stipulation and do not agree to its terms.

At hearing, Division and Company witnesses explained the Stipulation and were cross-examined. To provide a context for the Stipulation, all witnesses who filed testimony on the gas processing issue presented that testimony at hearing and were cross-examined. The Committee's pre- and post-Stipulation opposition to cost recovery is unchanged. Subsequent filing of an Allocation and Rate Design Stipulation, attached as Appendix 4, removes other intervenors' objections to gas processing cost recovery. We begin with a summary of these positions.

The Company testifies that it approached Utah regulators in early 1998 to explain the effect of the increasing amounts of low-BTU central-Utah coal seam gas entering its system. This gas is transported by affiliate Questar Pipeline Company. Though it contains high levels of inert carbon dioxide, the gas meets QPC pipeline specifications. Thus, the Company asserts, QPC is obligated under Federal Energy Regulatory Commission ("FERC") open-access rules to accept it. A "major safety risk" and an "acute problem that required relatively rapid analysis and response" are posed, the Company states, by this gas.

The Company believes declining BTU content ultimately will require changing appliance set points in the QGC service territory. If this were attempted at once, the cost is unacceptably large – over $100 million. When the magnitude of the coal seam gas problem became apparent in early 1998, the Company reports that research had just shown carbon dioxide removal would permit safe consumption of the coal seam gas. Providing this processing, it concluded, was the only option among those considered that it could implement in time to assure customer safety.

QGC thereupon contracted with QTS for cost-of-service gas processing service. Its testimony supports the choice of QTS as best both for getting the job done on time and for providing the service less expensively, at cost-of-service. Others, the Company testifies, would not have been satisfied with regulated rate of return. In the Company's view, carbon dioxide processing has successfully permitted it to manage BTU content as required by Commission Rule R746-320-2.B while meeting the goals of timeliness and assured customer safety.

The Division testifies that QGC's decision to enter the gas processing contract was "not entirely prudent," in part because of the influence of affiliate relationships. In Docket No. 98-057-12, Division witnesses concluded the QGC decision appeared to have been driven by the interests of Questar Corporation rather than the interests of QGC's customers. Affiliates, by Division calculation, could realize $6.3 million per year in revenues for gathering, transporting, storing, and processing coal seam gas. Thus, the Division asserts, the Company did not pursue relevant options such as refusing to take this gas. It did not, as a further example, seek changes in QPC's pipeline specifications at the FERC. Once it had decided to pursue gas processing, the Division says, QGC did not bid the entire gas processing project but contracted with an unregulated affiliate.

The Division testifies in Docket No. 98-057-12 that a well-documented QGC decision process, showing how all available alternatives were objectively analyzed, that is, at arms-length from affiliate interests, and the reasons why gas processing is the best among them, does not appear to exist. As a result, and even with the added time afforded by the present Docket, it cannot determine whether the choice of gas processing, and the contract which facilitates it, is prudent. Conversely, the Division testifies, it cannot conclude the choice was imprudent observing, instead, that it was "not entirely prudent." Based on this, and its conclusion that gas processing has effectively solved a real problem of customer safety, it therefore in the present Docket seeks a reduction in gas processing expense recovery. A reduction also can be supported, the Division testifies, by reducing plant depreciation expense and offsetting processing costs with the net revenues handling coal seam gas provides QGC's affiliates.

The Division's recommendation for reduced expense recovery is further supported by its analysis of the likely outcome had the Company pursued a case at the FERC. On equity and efficiency grounds, it argues a good case could have been made for requiring gas producers or shippers to pay processing costs. Since the southern pipeline, where gas enters the QGC system, was built to bring high quality gas to QGC customers, the shipper, QGC, which pays the bulk of pipeline costs, should expect delivery of gas of required quality. Pipeline specifications should have been set accordingly. In view of the fact that this has not occurred, the Division believes an equity issue exists.

The Division terms the safety risks and mitigation expense caused by the entry of coal seam gas into the QGC distribution system a "substantial external cost." Its economic analysis establishes that if producers of the coal seam gas do not bear ("internalize") these external costs, inefficient resource production and consumption decisions will occur.

Had QPC refused the coal seam gas, the Division believes producers would either have processed it themselves or appealed to the FERC to force pipeline delivery. The basis for refusal of this gas is found in paragraph 13.5 of the QPC tariff, which states: "Questar shall not be required to accept gas at any point of receipt that is of a quality inferior to that required by shipper or a third party at any point of delivery on Questar's system."

The Division speculates that the worst outcome if the issues had been taken to FERC is an order requiring QPC to deliver the gas but, to prevent the safety problem on QGC's system, after processing. QGC, as the largest shipper, may have been required, on a volumetric basis, to pay most of the processing costs. Other alternatives include requiring producers, as beneficiaries of open access, to pay; enforcing paragraph 13.5 as a reasonable way to maintain open access without imposing tighter pipeline specifications; and -- QGC's position in the present Docket -- requiring QGC as the entity whose high BTU requirements might be considered the cause of the problem, to pay. Given uncertainty about these outcomes, the Division seeks a reasonable middle ground. This middle ground, it testifies, is its recommendation to disallow half the processing costs for which QGC seeks recovery.

The Large Customer Group ("LCG") cites the ratemaking principle of cost causation to argue that QGC customers should not pay gas processing costs. LCG believes affiliate relationships influenced the QGC choice of gas processing. It presents an economic analysis similar to that of the Division which concludes that gas processing costs should be borne by gas producers in order to prevent inefficient production decisions. Notwithstanding these arguments, LCG, as a party to the Allocation and Rate Design Stipulation withdraws its opposition to recovery by customers of gas processing costs.

Recovery in rates of gas processing costs, the Committee testifies, is not supported by the record and is not in the public interest. To develop this position, the Committee relies on the ratemaking principle of cost causation. It believes the record is clear that, absent coal seam gas, a general decline in the BTU content of the gas supply would have been handled by QGC without gas processing. It is, the Committee asserts, coal seam gas production, and transportation by QPC, that causes the processing requirement. Because this is the cause, producers, the pipeline, or both, should bear processing costs.

The Committee disputes the QGC assertion that the cause of the problem is the high BTU requirement of the QGC system and hence customer safety.

In no other case, the Committee states, does a local distribution company like QGC directly pay the costs of gas processing. If processing instead is part of the cost of a particular gas supply, the Committee argues, QGC can make an economic decision whether or not to purchase it.

The Committee supports its position by reference to the economic analyses submitted by Division and Large Customer Group witnesses which conclude that, on equity and efficiency grounds, QGC customers should not bear gas processing costs in the manner proposed by the Company. The Committee believes QGC's choice of the processing option shows the influence of affiliate relations. It relies in part on Division testimony to the effect that QGC affiliates realize several million dollars per year of benefits from gathering, transporting, storing, and processing coal seam gas. It cites FERC decisions in which processing costs have been imposed on producers to support its contention that options QGC did not pursue -- among them, requesting tighter pipeline specifications, imposition of paragraph 13.5 -- are not only likely to have borne fruit but are demonstrably in the public interest whereas gas processing paid by QGC customers is not. An unaffiliated local distribution company, the Committee claims, would not have selected this option, but, with clear prospects for success, would have taken its case to FERC.

The following reasons are given by the Company and the Division for the alterations in their positions which led to stipulation. The Division believes the safety problem for customers caused by low-BTU coal seam gas is real and that gas processing is effectively solving it. Combined with its inability to conclude that the decision to enter the contract is imprudent, this leads the Division to support recovery of 50 percent of processing costs. Though the Stipulation would permit the Company to recover $5 million (about 68 percent of its original request), the Division cites as an offsetting factor the Stipulation's limitation of recovery to a maximum of $5 million per year for a five-year period beginning June 1999. By setting a maximum on recovery and limiting the term, the Division believes ratepayer risk is mitigated and effectively capped. The Stipulation also gives regulators the opportunity to argue, in subsequent dockets during the five years, the case for recovery of a lesser amount. In the sixth year, the Company must make the case for recovery of anything at all. As a result, ratepayers no longer are responsible for all gas processing costs. To reach this, the Division agrees to give up a claim to revenues generated by processing gas for third parties. At present, this is a small amount and it is expected to remain small so long as QGC requires most or all of the processing facility's capacity. Ratepayers are protected by the cap from the effect of other factors, such as construction of Mainline 104, a pipeline which may carry coal seam gas away from the QGC system, thus reducing the processing requirement, the Division states. For the Company, the Stipulation recognizes the Company's obligation to manage BTU content to protect customer safety and reasonably resolves a cost recovery issue in doubt for two years.

As the record on a dispute that has carried through two dockets has developed, we face the question whether the contested CO_2 Stipulation resolves it in a way that is both reasonable and in the public interest. The answer turns first on the problem that lies at the heart of the issue. QGC asserts the problem is customer safety; CCS, production and transportation of coal seam gas. It turns second on whether we must rule on the decision to enter the contract (whether prudent) or instead can examine the outcome of that decision (whether reasonable).

QGC maintains that its long-standing but unusually high BTU requirement creates a safety problem for customers when lower-BTU coal seam gas enters its system, an occurrence it says cannot be prevented. As a public utility, QGC argues it is obligated to redress the problem effectively and is entitled to recover from customers the reasonable costs of doing so. The Committee rejects this description of the problem and its cost-recovery consequence. In its view, the problem is production and transportation of low-BTU coal seam gas; it follows that producers, shippers, or both, are the parties from which cost recovery must be sought.

We believe this difference in problem statement is relevant to the period before coal seam gas was recognized as a specific problem requiring swift and effective action, that is, as distinct from the earlier, and as the Company testifies, continuing general decline in the BTU content of gas supplies of which the presence of coal seam gas was but a part. The record shows this to have been prior to early 1998, during which time the Company considered a number of options. The significance of coal seam gas was growing during the 1990's, but, the Company testifies, it was not until late 1997 or early 1998 that its increasing volumes became a significant threat. At that point, the Company states, research revealed that removal of carbon dioxide would permit the safe consumption of coal seam gas in customers' appliances. Once coal seam gas became a persistent threat to the BTU content of QGC's gas supply, customer safety was threatened and an effective response was mandatory.

The record is insufficient to permit us to determine whether the Company's analysis of options prior to early 1998 was sufficiently objective and thorough, that is, to reach a conclusion whether options were ruled in or out as a result of the influence of affiliate interests. Nor can a sufficient record be developed. We address this further below. The record leaves no doubt, however, that by early 1998, the number of effective alternatives had narrowed to two: process the coal seam gas or keep it off the distribution system. QGC chose to process the gas. If the gate had been closed to coal seam gas, QGC states, demand on the southern part of its system could not have been met. This assertion is uncontroverted.

The most troubling question is whether the contract between QGC and its unregulated affiliate, QTS, was prudently entered. The Company applied for a decision on it in Docket No. 98-057-12, but not in the present proceeding, where the Committee keeps it alive by asserting that the decision to enter the contract is imprudent and recovery from customers of gas processing costs incurred pursuant to it is unreasonable. Clearly, QGC has the burden to demonstrate the decision to enter the contract is a prudent one. Parties differ as to whether it did so successfully. But whether or not QGC met this burden, we can and do conclude that its decision to procure gas processing has yielded the required result, that is, it has effectively protected the safety of its customers. This means the costs of gas processing can be legitimately recovered in rates. The amount that should be recovered remains to be determined.

Having accepted the Company's representation that the problem at issue here is customer safety, and that gas processing is a reasonable way to meet it, it remains to decide the amount of gas processing costs that reasonably should be recovered. Two discussions on the record help us to reach this decision. Both concern the likely outcome had FERC considered the issue of who ought to pay to process gas. The Committee asserts that the argument that producers or shippers or both would have been assigned cost recovery responsibility had a strong likelihood of success. Two FERC cases on point are cited as support. But QGC in response argues cases offering a different view and contends the facts of the present case and the two cases are different. This dispute is hypothetical; we do not find sufficient record support to suggest the probable outcome had the case gone to FERC.

The Division confronts this uncertainty in a different way by focusing on the probable consequences of alternative FERC decisions ranging from assigning full cost recovery to producers, assigning these costs, because of the characteristics of its system, to QGC, and alternatives in between. This is a useful way to consider the uncertain outcome of a case that would have been vigorously contested. The Division analysis, which we have summarized above, leads it to recommend recovery of 50 percent of gas processing costs. We therefore find record support for a conclusion that a significant share of the cost recovery burden would have been a QGC, and therefore a local-distribution customer, responsibility.

On this basis, we further conclude that the Stipulation reasonably resolves the gas processing cost recovery dispute. The Company testifies that the settlement, which allows it to recover but 68 percent of the costs of gas processing, is reasonable. From its point of view, there is value in ending a two-year-old dispute. The Division settles for recovery not of its recommended 50 percent but of 68 percent of the gas processing costs because the Stipulation caps the amount at $5 million per year for a period of five years. This, the Division holds, effectively caps and mitigates the risks to which ratepayers are exposed. Under terms of the Stipulation, regulators can audit gas processing costs in each of the five years and can recommend recovery of something less than the $5 million. Thus the Division argues the tradeoff to permit recovery of a greater portion of the costs but to cap the recovery at a maximum and to mitigate the risk ratepayers bear by limiting the applicable period to five years is both worthwhile and reasonable.

We conclude that the Stipulation offers a fair and reasonable settlement of the cost recovery issue. We accept the Stipulation.

F. NON-REGULATED POSTAGE EXPENSE

QGC seeks recovery of $2.3 million expended for postage to mail bills to customers during the test year. No party disputes this amount as a reasonable postage cost. The Division, as it did successfully in Docket No. 99-035-10, argues for a reduction in recoverable expense owing in large part to the effect of an intervening affiliate relationship. With correction of an arithmetic error and adoption of a modification suggested by the Company, both of which reduce the adjustment amount, we accept the Division's recommendation.

The Company mails bills to customers monthly. Postage for each is approximately 26 cents. GasLight News, a newsletter used by the Company to communicate with its customers, is included in the billing envelope a number of times each year. It contains educational and safety messages about natural gas utility service, and from time to time carries corporate image-building and promotional statements and messages about the services and products sold by its unregulated affiliate, Questar Energy Services (QES). Often, the billing envelope will contain flyers advertising these unregulated services and products. The subjects appearing in GasLight News, the number of times each year it is sent to customers, and whether to include advertising flyers in the envelope, are matters of management discretion. Neither the flyers nor the newsletter, however, increase the postage required to mail the bill.

As presented by the Division, the issue is whether recoverable postage cost should be reduced by allocating a share to an unregulated function and disallowing another share incurred to disseminate institutional and promotional advertisements. Commission Rule R746-406-1 prevents recovery of the costs of such advertisements from ratepayers. ("no electric or gas utility may recover from a person, other than shareholders or other owners of the utility, a *direct or indirect* expenditure by the utility for political, promotional or institutional advertising." Emphasis added.) The Division's final position is a recommended disallowance of about 37 percent, or $860,000, of the $2.3 million incurred for postage during the test year. The Company opposes the adjustment. No other party testifies on the subject.

In all principal respects the issue here is the same as that considered and resolved by the Commission in Docket No. 99-035-10, a PacifiCorp general rate case (Report and Order issued May 24, 2000, pages 26 - 29.) There, the Commission concluded that postage cost must be shared in order to correct an inequity and to prevent subsidization of unregulated business activity by the customers of the regulated utility. QGC raises two points not fully addressed in that Docket. We consider whether these, and renewed argument on points previously found persuasive by the Commission, now necessitate a different conclusion.

Economic regulation of public utilities has long understood, and we have repeatedly acted upon this understanding, that affiliate transactions can be used by the controlling corporate entity as the means to exceed the rate of return allowed by regulators as a cost of providing utility service. When the utility provides a product or a service to an affiliate company, this Commission's decisions require a charge for it which reflects the higher of the cost the utility incurs to provide the product or service (the embedded cost), or an appropriate market price for it. The higher-of-cost-or-market policy protects ratepayers and prevents the subsidy that otherwise would flow from the utility to the affiliate. In the PacifiCorp Docket, the Commission concluded that an inequitable result and a subsidy would occur if the shared costs of providing mailing service were not allocated to the utility and the affiliate.

Nothing on the record in the present Docket causes us to revise this analysis. But, as the Commission stated in the prior Docket, this regulatory prescription holds unless it would prevent a transaction which benefits both the Company and its ratepayers, in which case it may be appropriate to consider incremental rather than embedded costs. The Company's assertion that ratepayers benefit from the QES advertisements, plus the fact that incremental postage costs are zero, form the basis of its opposition to the Division's proposal to allocate these costs.

Our review of this record reveals two points raised by the Company which must be considered as we evaluate its position. The first point is the assertion that ratepayers do benefit from the receipt of messages about unregulated products and services, making incremental costs rather than embedded costs the appropriate decision criterion. The second point is a QGC claim that an attempt to recover postage costs by charging QES for mailing its advertisements would force QES to cease mailing anything in the QGC bill. As a consequence, states the Company, it would not recover a reasonable cost of providing utility service.

The presumption of reasonableness regulators typically accord management's decisions to incur costs to provide utility service is absent when the costs arise in an affiliate relationship. (*US West Communications, Inc. v. Public Service Commission of Utah*, 901 P. 2d 270, 274 (Utah 1995) "[W]e do not think an affiliate expense should carry a presumption of reasonableness.") Because of this, we must note that the two points are assertions rather than the conclusions of arguments fully developed on the record.

First, QGC opines that ratepayers benefit from advertisements for the products and services of unregulated affiliates and so incremental rather than embedded costs should be considered in order that a transaction beneficial not only to the Company and its sister entities, but to ratepayers, is not prevented. Our review of the record to substantiate the claimed ratepayer benefit reveals survey results showing that only 41 percent of QGC's customers believe use of the billing envelope to advertise the products and services of unregulated affiliates is acceptable. On this basis, the Division avers that unregulated messages do not benefit ratepayers. The Company interprets the results the other way: 41 percent might find the messages useful. Since the survey is apparently silent on the point, each party is speculating. The Company's statement that QES will cease using the billing envelope if it is charged for postage, in the amount indicated by the Division's proposed disallowance, is germane as an indirect indication of ratepayer value. According to the Company, QES does not find the advertisements useful enough – ratepayer response to them is low -- to justify that level of expense to mail them. Ratepayer value must be less than the cost of mailing advertisements to them. These considerations support a conclusion that ratepayers would not be harmed if adherence to the embedded-cost approach prevented placement of messages from QGC's unregulated affiliate in the regulated services billing envelope.

Before reaching this conclusion, we consider a statement in the Company's final brief. There, the Company declares: "Questar Corporation and Questar Gas believe that the corporate entity is entitled to utilize the economies of scale and scope among its subsidiaries as long as this use does not disadvantage the utility customers of Questar Gas." By asserting that an adverse ruling may prevent the realization of economies of scale and scope, the Company may simply be rephrasing its position that incremental costs, which in this case are zero, rather than embedded costs are an appropriate basis for a decision. It appears the assertion is that if mailing costs are allocated, QES will forego the opportunity to use the billing envelope, an opportunity which would have advanced Questar Corporation's interests.

Though "economies of scale and scope" are undefined terms on this record, they are common enough in the discipline of economics, where economies of scale are held to exist if the average cost a company incurs to produce a product falls as the level of output of the product expands. The record, which contains nothing on scale economies, leaves open the question whether they exist in the case before us. The record does not suggest a relevant application of the concept here. Furthermore, if scale economies do exist here, the effect would be to reduce mailing costs for both the utility and the affiliate, thereby reducing revenue requirement. Economies of scope, the possible application of which is also not developed on the record, in theory exist when a single entity can produce two or more products at lower total cost than would be experienced if each instead were independently produced by separate entities.

We are aware that, within the law, Questar Corporation may organize as it sees fit, and that the utility may pursue unregulated business activities. A decision to allocate mailing costs does not dictate organizational structure. Our concern rests with the transactions of the regulated utility.

On this record, QES has inferior, though lower in postage cost, alternatives by which to mail its advertisements. If one of these were used in order to save money, QES, as the Division testifies, would lose the benefits of direct association with QGC. A tangible benefit is free use of QGC's customer mailing list, which QES would otherwise have to acquire for a price, to target a specific audience. An intangible benefit is the goodwill and brand identification that comes from immediate association with the company that for decades has successfully provided home energy. It is not so simple, therefore, to argue, if this is the Company's intention, that direct assignment of all postage cost to the regulated utility, when both affiliate and utility benefit, is a legitimate case of the corporation realizing economies of scope. In order to adequately address economies of scope, information covering the costs of alternatives available to QES to distribute its advertisements, the value of tangible benefits like access to QGC's customer mailing list, and the value of intangible benefits like goodwill and brand identification would be required.

Applicability of the statement in the Company's brief is limited by its own terms to incidences when no disadvantage to ratepayers arises. We find, however, that ratepayers are disadvantaged if postage cost is not allocated. The Division argues an opportunity cost is involved. Not only are revenue requirement and therefore rates reduced when costs are allocated -- the opportunity cost is the failure to do so -- but the Company could sell to other companies the envelope space that it gives free to its affiliate. The opportunity cost is foregone revenue, and this too would decrease rates.

All this is merely to entertain the Company's declaration about scale and scope economies. We intend no implication for policy other than that which flows from the decision to allocate postage costs in order to resolve an inequity and to prevent the subsidization of an affiliate. We conclude that the use of embedded costs in the higher-of-cost-or-market test remains appropriate because the record does not support the Company's assertion that ratepayers benefit from the affiliate's advertisements.

Second, the Company asserts that refusal to permit full recovery of postage costs from utility ratepayers will deprive it of the opportunity to earn the allowed rate of return because the affiliate will cease using the billing envelope to distribute messages and accordingly will not pay any of the allocated postage cost. The Division labels this claim "hearsay," and indeed, the Company's witness merely says he talked to persons from QES who told him so. A Commission finding cannot be based on hearsay alone.

The Company, however, also informs us that QES does not include its advertisements in billing envelopes if doing so increases the postage required. Be this as it may, we have no knowledge of QES's advertising plans or budget, and nothing save the Company's assertion about the possible impact of a postage charge to reveal the considerations which might lead QES to place, or not to place, its messages in QGC's bills. We have no jurisdiction over QES so this information is not readily accessible. Common sense tells us postage cost is but one among the factors which could drive the affiliate's decision. Therefore, we cannot on this record conclude that a decision to allocate postage costs by itself will end QES's use of QGC's billing envelopes, thus depriving QGC of the opportunity to recover legitimate and reasonable costs of providing utility service. If this were the case, however, it would be recognized in the Company's next general rate case.

Having fully considered the proposed adjustment and arguments against it, we conclude that the higher-of-cost-or-market test is applicable in this case. The Company's assertion of ratepayer value is unsupported on this record and is rejected. Its claim that incremental costs should guide the decision therefore fails. We also reject the assertion that an allocation of postage costs will deprive the Company an opportunity to recover all legitimate and reasonable costs of providing utility service.

QGC also asks the Commission to apply prospectively any decision reached to allocate postage costs, to give it time to alter its behavior without facing a revenue requirement "penalty." We cannot reach a decision about the costs of providing utility service that are legitimate and reasonable for recovery in rates and fail to act upon it. Here, we have decided that a portion of postage cost should not be recovered from ratepayers. To place it in revenue requirement nonetheless, in order to send the Company a message about a new regulatory requirement and so to allow it time to alter its behavior, would be improper. This is particularly true because the record does not allow us to conclude that the affiliate will cease to use the billing envelope to distribute its messages if doing so is no longer free. Under these circumstances, the greater harm is to ratepayers, who would have no option but to continue buying Company-supplied natural gas at rates higher than they ought to be. The decision to allocate postage costs will be reflected in the rates for service this Report and Order makes effective.

The adjustment to postage costs we will allow is a reduction of $607,906, derived as follows. First, the Division calculates a cost per piece mailed in the billing envelope of approximately 14 cents. This is incorrect. The proper amount, as the record shows, is 11.2 cents each. Second, the Division adjusts for the effects of both unregulated messages and unrecoverable advertisements. We agree this should be done, but find the Division has mis-estimated the proportion of these at 50 percent of the GasLight News content. The record for the test year shows, as the Company argues, that the correct figure is approximately nine percent. We agree. We reject the contention, which is the Division's rationale for the 50 percent adjustment, that management control of GasLight News content makes equally likely (that is, 50 - 50) the presence of permissible and impermissible messages. Applying both corrections reduces the Division's proposed adjustment to $607,906.

G. LOW INCOME WEATHERIZATION PROPOSAL

The Salt Lake Community Action Program and the Crossroads Urban Center propose a low-income weatherization program which would make available $250,000 to weatherize the residences of low-income Company customers. The funds, which would come from general rates, would supplement the efforts of the Utah Department of Community and Economic Development (DCED). This approach would minimize administrative expenses. Benefits of the program cited by SLCAP/CUC include reducing the energy burden (percent of household income spent for energy, primarily electricity and heating fuel) of the participants, promoting cost-effective energy conservation and economic development, and leveraging federal funds to meet the requirements of federal law. Testimony indicates that the savings to participants could be substantial. National estimates are that weatherization programs save an average of $193 per year, and yield non-energy benefits of $976, over the life of the weatherization measures. These programs can improve safety in low-income residences as some families are reluctant to request utility assistance for fixing faulty appliances fearing the appliance will be shut off. SLCAP/CUC argue the program will not overly burden non-participating customers as its cost per residential customer will be approximately $.03 per month. In addition, these expenditures may be offset if the program reduces the costs of collections and problem accounts.

The Committee believes the weatherization program will decrease energy burden, promote conservation, conserve a nonrenewable resource, provide environmental benefits, and promote safety by repairing faulty appliances which may endanger lives. The Company does not oppose the program as long as the financial impact on customers is minimal. With the exception of IGU, which argues in its final brief that such proposals are better handled by the legislature, intervening parties do not oppose the program. Four public witnesses testify in support of the program; one opposes it.

We conclude that ratepayer funding of the proposed weatherization program is in the public interest and will allow recovery of the expenditure through general rates. In support of this conclusion, we find that the program meets the criteria set forth in the Commission's May 24, 2000 Order approving a lifeline rate in Docket No. 99-035-10. In addition, we find that this program will promote cost-effective energy efficiency measures that will conserve resources and provide environmental benefits. The program will minimize administrative costs while providing benefits to participants and nonparticipants. The program also addresses a safety issue that may otherwise be difficult to alleviate. For these reasons, we approve the funding of $250,0000 for weatherization to be administered by DCED.

H. IMPUTED INCOME TAX CALCULATION

Test-year income taxes are calculated based on adjusted test-year results in which the deduction for interest expense is obtained as the product of the weighted cost of debt and the adjusted rate base. This method of determining interest expense is often referred to as "interest synchronization." The income tax calculation includes the South Georgia Deferred Income Tax Amortization of $921,470 and Section 29 Income Tax Credits of $1,878,374. Income taxes are calculated using a federal income tax rate of 35 percent and an effective state income tax rate of 4.6537 percent. In the computer model of the Company's results of operations, each of the previous adjustments has an associated income tax effect. This adjustment is the difference between the calculated test-year income taxes and the sum of income taxes reported on an unadjusted basis and the income taxes associated with all previous adjustments. It has been used in the Company's previous general rate cases and is undisputed in this case. It increases system income taxes by $1,012,285.

I. SUMMARY

A summary of the effect of our decisions is shown in Appendix 1, attached to this Order. In conjunction with the Company's reported unadjusted results of operations, the decisions reached in Sections A through H establish the adjusted results of system operations. The adjusted system results, including both gas supply and distribution non-gas results, are then apportioned to the Wyoming and Utah jurisdictions. The Utah distribution non-gas results are then separated from the total Utah results. This is the basis for determining the change in distribution non-gas revenue requirement. In order to calculate revenue requirement, we have used the values of those adjustments support by the Division in Section D. Given our decisions, the change in distribution non-gas revenues ordered in this Docket is $13,497,484, an amount necessary to provide the Company an opportunity to earn an allowed rate of return on equity of 11 percent, or an allowed rate of return on rate base of 9.8226 percent, based on a 1999 test year. Of this amount, an interim award of $7,065,000 granted on January 25, 2000, is currently being recovered in rates.

III. PRICING OF TARIFFED RATE SCHEDULES

Our practice is to employ an acceptable class cost-of-service study to guide the apportionment or spread of adjusted jurisdictional revenue requirement to classes of service. The design of rates in each class follows established ratemaking principles.

A. COST OF SERVICE AND SPREAD OF REVENUE INCREASE

1. Bad Check Fees

The Company currently charges $15.00 for customers' returned checks but proposes to increase the amount to $20.00, the maximum amount allowed by Utah law. In support of its proposal, the Company testifies that the average cost to process a bad check through the system is $20.34, and that most merchants and businesses charge $20.00. Neither the Division nor the Committee takes a position on this issue. We approve the Company's proposal, which increases revenues by $37,400. This amount is already included in the determination of revenue requirement in Section 2.C above.

2. Home Energy Evaluations

The Questar Gas tariff currently includes a fee of $15.00 for performing home energy evaluations. The Company proposes to remove energy evaluations from the tariff. It has not actively performed home energy evaluations for over ten years, and almost no evaluations have been done in the last five years. Since customers no longer ask for evaluations, the Company is no longer staffed to provide the service. The Division takes no official position on this issue in this Docket, but supports the proposal. The Committee takes no position. We approve the Company's proposal, which has no revenue requirement effect.

3. Separation of Firm Transportation Into Bypass and Non-Bypass Schedules

The firm transportation rate is open to customers who meet the tariff provisions and who have bypass options. The Division testifies that since its adoption in 1994, some customers not intended to qualify for service on this schedule have done so even though their volumes do not meet the minimum bill level. These customers simply pay the minimum bill.

The Company proposes to address this problem by creating two rates. FT-1, a bypass rate intended to retain customers having alternative transportation options, would continue the existing FT rate including any percentage increase resulting from this proceeding. Eligibility would be limited to customers having annual usage of more than 4 million decatherms or annual usage of at least 100,000 decatherms and a location within five miles of an interstate pipeline. FT-2, a non-bypass rate, would be available to firm transportation customers who do not qualify for the FT-1 rate. The FT-2 rate would be allocated a uniform percentage increase of the final revenue deficiency in this proceeding. The Division supports this proposal. It is adopted by parties to the Allocation and Rate Design Stipulation.

The Committee, which is not a party to this Stipulation and opposes it, calls attention to the public witness testimony of one of the members of LCG. LCG is a party to the Stipulation. This entity, Central Valley Water Reclamation District, would not qualify for the FT-1 rate but desires to receive service pursuant to its terms. The Committee worries that there may be other large customers who similarly will request special consideration. The Commission, having the ability to address a customer's claim of uniqueness, does not find the Committee's concern sufficient reason to reject the firm transportation rate design proposal which is otherwise unopposed and reasonable. We will accept the Company's proposal to create FT-1 and FT-2 rates as stated in the Stipulation.

4. Allocation of CO_2 Gas Processing Costs

Carbon dioxide gas processing costs approved for recovery in rates must be allocated to classes of service. Prior to the Allocation and Rate Design Stipulation between the Company, the Division, the Large Customer Group, and the Industrial Gas Users, submitted June 6, 2000, the Division recommended allocating gas processing costs based on the volumes each class consumes. The Division reasons that because the FERC open access policy in theory benefits all, but particularly transportation, customers through increased gas flow and lower well-head prices, all customers should share in cost recovery. A volumetric allocation would produce an appropriate cost sharing among classes, it believes. The Committee adopts this position.

Pre-Stipulation, the Company proposed to allocate the costs in the same relationship as the sum of all other costs in the test year, using a system overhead allocation factor. LCG advocated the number of customers in each class as the allocation basis. No other party testifies on the issue.

The Allocation and Rate Design Stipulation proposes a "double weighted" allocation, described in the Stipulation, as the fair settlement of this dispute. This allocates about five percent of gas processing costs to transportation customers, more than the Company's original proposal but eliminating transportation customers' opposition to recovery by them of much gas processing cost at all. Residential and other sales customers, however, for whose safety the gas processing was undertaken, would be responsible for recovery of about 95 percent. Though the Division continues to believe that transportation customers should pay as much of this cost as feasible, it now agrees that a volumetric allocation, which would allocate approximately 23 percent of gas processing costs to transportation customers, would raise their rates about 50 percent. An increase of this order poses the likelihood of bypass. On reflection, the Division perceives its original proposal as a short-run solution with probable and unacceptable long-run consequences. Were bypass to occur, fixed costs allocated to these customers would no longer be recovered from them but would become the responsibility of all remaining customers. In the long-run, the Division states, bypass would produce a cost responsibility for remaining customers about the same as that in the Stipulation. LCG testifies that transportation customers can adapt gas-using equipment to the higher carbon dioxide levels of coal seam gas and thus bear no part in the safety concern advanced by the Company as the reason for gas processing. LCG opposes a volumetric allocation of the costs, but supports the share it would bear as a result of the Stipulation. The Committee opposes recovery of gas processing costs, but supports the Division's original position advocating a volumetric basis for allocation should the Commission permit recovery of these costs from ratepayers. The Committee opposes the Allocation and Rate Design Stipulation.

Except for the Committee's opposition to recovery of gas processing costs and its adoption, in the alternative, of the Division's original allocation proposal, the Stipulation provides an allocation method all other parties agree is a fair and reasonable settlement of their differences. Less of these costs are allocated to transportation customers than the Division would prefer, and more than the transportation customers argue they conceivably could be responsible for on a cost-causation basis.

In considering the Committee's opposition to the Stipulation's method of allocating gas processing costs, and its adoption of the Division's original position, we are persuaded the reasons the Division abandons that position are correct. Its argument for a volumetric allocation does not support a nearly 50 percent increase in costs for transportation customers, particularly if bypass, which shifts responsibility for fixed cost recovery, is the consequence. This possible result suggests the initial Division proposal may not achieve its cost-allocation purpose. The Division also defers to the argument that transportation customers bear no part in the safety problem gas processing addresses. A volumetric allocation of gas processing costs, we conclude, cannot be supported on this record. The settlement offered by the Stipulation, which will allocate about five percent of gas processing costs to transportation customers, is reasonable and we will accept it.

5. Spread of Increase in Revenue Requirement

The Company proposes a spread of the revenue increase, excluding CO_2 processing costs, to all classes of customers by a uniform percentage increase, an approach which compares closely to the class cost-of-service study results and is consistent with prior rate cases. Based on our prior decisions in this order, the initial revenue increase to be spread to classes on a uniform percentage basis, excluding CO_2 processing costs, is $8,497,484. The revenues from tariffed rate schedules (where revenues from Connection Fees and New Premise Fees are included in the revenues for GS-1 and GS-S rate schedules) and Account 486.0, Natural Gas Vehicle Equipment Leases, are each increased by 4.4614 percent. The resulting initial revenues, i.e., adjusted test-year revenues plus the spread of $8,497,484, are shown in the first column of Table 1, below.

Excluding the Natural Gas Vehicle Equipment Sales and Leases, the Bypass Firm Transportation (FT-1) rate schedule, and other revenues (Accounts 487 and 488, and Colorado revenues), the Non-Bypass Firm Transportation (FT-2) rate schedule accounts for 0.7442 percent and the Interruptible Transportation (IT and IT-S) rate schedules for 1.7455 percent of the initial class revenues. The Allocation and Rate Design Stipulation calls for doubling the percentage weight for IT/IT-S and FT-2 schedules to 3.4911 percent and 1.4883 percent, respectively. The other schedules receive a pro rata sharing of a 2.4897 percent reduction. The resulting allocation of CO_2 processing costs to rate schedules is summarized in Table 1.

Table 1: Allocation of CO_2 Processing Costs

Rate Schedule	Initial Revenues[1]	Initial Weighting	Double Weighting	Pro-Rata Reduction	Total Weighting	Allocation of CO_2 Costs
GS-1, GSS[2]	187,616,373	95.4686%		-2.4375%	93.0311%	4,651,553
F-1	3,009,275	1.5313%		-0.0391%	1.4922%	74,609
F-3	219,459	0.1117%		-0.0029%	0.1088%	5,441
Bypass Firm Trans., FT-1[3]	1,880,249	n.a.			n.a.	n.a.
Non-Bypass Firm Trans., FT-2[2]	1,462,416	0.7442%	0.7442%		1.4883%	74,415
Natural Gas Vehicle Sales	351,007	n.a.			n.a.	n.a.
Natural Gas Vehicle Leases	213,139	n.a.			n.a.	n.a.

Interruptible Sales	783,685	0.3988%		-0.0102%	0.3886%	19,430
Interruptible Transportation	3,430,335	1.7455%	1.7455%		3.4911%	174,553
Accts 487 & 488, Colo. IC	5,992,599	n.a.			n.a.	n.a.
Total	204,958,537	100.0000%	2.4897%	-2.4897%	100.0000%	5,000,000

[1] Includes Adjusted Test-Year Revenues of $196,461,053, an increase of $8,497,484 based on uniform 4.4614 percentage spread.

[2] Includes Service Initiation and New Premise fees

[3] Firm Transportation (FT) split 56.25 percent to FT-1 and 43.75 percent to FT-2.

Based on an initial revenue increase of $8,497,484 spread to rate classes on a uniform 4.4614 percentage basis and a revenue increase of $5 million based on the Allocation and Rate Design Stipulation, presented in Table 1 above, the spread of the final increase in revenue requirement is summarized in Table 2 which follows.

Table 2: Spread of Final Increase In Revenue Requirement

Rate Schedule	Adjusted Revenues	Percent Change	Change In Revenues	Final Revenues	Cost Of Service	Difference COS - Rev.
GS-1, GSS[1]	179,603,609	7.05%	12,664,317	192,267,926	192,276,784	8,858
F-1	2,880,754	7.05%	203,129	3,083,883	3,018,176	(65,708)
F-3	210,086	7.05%	14,814	224,900	111,069	(113,830)
Bypass Firm Trans., FT-1[2]	1,799,947	4.46%	80,302	1,880,249	n.a.	n.a.
Non-Bypass Firm Trans., FT-2[2]	1,399,959	9.78%	136,872	1,536,831	n.a.	n.a.
Natural Gas Vehicle Sales	336,016	4.46%	14,991	351,007	n.a.	n.a.
Natural Gas Vehicle Leases	204,036	4.46%	9,103	213,139	n.a.	n.a.
Interruptible Sales	750,215	7.05%	52,900	803,115	923,572	120,458
Interruptible Transportation	3,283,831	9.78%	321,056	3,604,887	3,655,109	50,222
Accts 487 & 488, Colo. IC	5,992,599	0.00%	0	5,992,599	n.a.	n.a.
Total	196,461,052		13,497,484	209,958,537		

[1] Includes Service Initiation and New Premise fees

[2] Firm Transportation (FT) split 56.25 percent to FT-1 and 43.75 percent to FT-2.

Only the Committee suggests it may be more appropriate to spread the revenue increase to rate classes based on cost-of-service study results. This position is based on its understanding that approximately $296,000 will be over-collected from the GS-1 rate schedule if the revenue increase is spread on a uniform percentage basis. Table 2 shows the class cost-of-service results using the Company's model. A comparison of these results with the spread of the revenue decisions is shown in the last column. This shows that the final revenues from the general service class, GS-1 and GSS, are only $6,310 less than cost-of-service. This result affirms our spread decisions.

We note, however, that based on cost-of-service results, there is apparently an extreme over-collection of revenues from Stand-By/Supplemental Sales (F-3) and a relatively large under-collection of revenues from Interruptible Sales. These issues were not addressed in this proceeding, but should be addressed in a future proceeding should these imbalances continue. We also order the Non-Bypass Firm Transportation (FT-2) be included in future cost-of-service studies.

In the next distribution non-gas rate proceeding the Company should include in its application an exhibit showing, by rate element, the actual annual billing units, the current and proposed rates, and the current and proposed revenues. For each rate schedule, the effect on annual billing units of unbilled revenues and test-year adjustments to revenues, such as temperature normalization of GS revenues and annualizations for other schedules, should also be shown.

B. DESIGN OF RATES

1. Customer Charge and Meter-Based Customer Charges

No party proposes any change to the $5 customer charge applicable to general service rates. To minimize rate-design issues in this case, the Company uses the method approved in Docket No. 95-057-02 to calculate the Class II, III and IV meter-based customer charges. These depend upon the final revenue requirement approved in this Docket. The Division supports the Company's proposal, while the Committee did not take a position on this issue. We approve the Company's proposal.

2. General Service Degree-Day Change

The Company's practice has been to calculate normal degree days using the same time period as the National Weather Service, which is the 30 years ended each decade. The normals currently in use include data through December 31, 1990. Weather normals are scheduled to be updated to reflect the 30 years ended December 31, 2000. The Company proposes to adopt the 30-year period ended December 31, 1999, as the definition of normal degree days for the purpose of designing new rates based on the final revenue requirement approved in this case. The Commission approved similar treatment in Docket No. 89-057-15, a case also filed one year prior to the scheduled update of normal temperatures. The Division does not dispute the change in degree day calculations proposed by the Company. The Committee takes no position on this issue. We approve the Company's proposal.

3. General Service Winter/Summer Rate Differential

In 1968 the Commission approved a winter/summer rate differential based on the higher winter peak demand for natural gas relative to summer demand. The Company now proposes to discontinue this rate differential. The Company states that the seasonal change in rates has, at times, confused customers, and believes that most customers would welcome a more understandable, simplified and stable rate. This change would also, for the majority of customers, help to lower bills in the winter when they are typically high and only slightly increase them in the summer when bills are typically lower. Customers in Utah and Wyoming have the equal-payment option, and approximately 40 percent of customers have chosen it. The Company notes although its Wyoming customers have not had a summer/winter rate differential for years, no measurable behavioral difference between Wyoming customers and Utah customers exists that is attributable to the summer/winter rate differential.

The Division opposes the Company's proposal. Because of the strong winter peak in demand, natural gas costs more in the winter than in the summer. Properly viewed, there is a difference in both the commodity cost and the facilities cost. That difference should be reflected in the retail price in order to send the appropriate price signal to customers, it states. Space heating is the largest use for natural gas, and the cause of the winter demand peak. The pursuit of conservation of that resource would be undermined if the relative price of winter usage was reduced by eliminating the summer/winter price differential. Even if customers were totally unresponsive to the price signal, equity considerations argue for the preservation of that differential. Customers whose usage is more concentrated in the off-peak season (e.g., due to relatively less space heating) deserve to pay less than customers who consume the same amount annually but whose usage is more concentrated in the winter, since the former customers impose a lower cost burden on the system. The Committee does not address this issue.

We agree with the Division's reasoning, and will not approve the Company's proposal. In this instance, we believe the efficiency, equity and conservation objectives outweigh the objectives of simplicity and customer understanding. The availability of an equal payment plan does not alter the information that prices are expected to convey.

4. Municipal Transportation (MT) Rate Design

The Municipal Transportation (MT) rate schedule was originally established by stipulation on October 26, 1999, in Docket No. 98-057-01. The Commission issued its Report and Order on April 26, 2000, adopting the rates, charges, and terms and conditions set forth in the Stipulation, including the initial MT rate of $0.23084/Dth plus a facilities balancing charge of $0.06/Dth. In addition, the MT rate is subject to an administrative charge of $8,000 and a monthly meter-base customer charge. Service requires a load factor of at least 15 percent. By terms of the Stipulation, the rate schedule remains in effect until superseded by Commission order in a general rate case.

IMGA proposes three changes in the calculation of the MT rate: (1) to include Firm Transportation (FT) volumes in the denominator when calculating the $/Dth for the MT rate, (2) to allocate property taxes and gross receipt taxes on a net plant factor rather than a gross plant factor, and (3) to reduce the rate to account for an alleged double charging of meter-based and administrative charges.

The Company recommends no change in the current MT rate. Questar Gas argues that because there are as yet no MT customers and therefore no actual data or experience upon which to rely, it would be premature to make any changes in the rate schedule. The basis upon which the Commission issued its order and upon which the stipulation was reached in Docket Number 98-057-01 should continue until customers are taking service and analysis can be performed.

Since no customers yet take service under the MT rate, we are unwilling to change the rates contained in the Stipulation, with the exception of the applicability of the administrative charge to multiple delivery points. The administrative charge is more fully discussed in Section B.6. We expect the Company, using actual experience, to develop a cost-of-service basis for the MT rate, as well as the FT-2 rate, in its next proceeding.

5. Daily Gas Balancing Provisions

Tariff No. 500, paragraph 5.10, addresses daily gas balancing and provides for a discretionary \$15 per Dth penalty when a transportation customer (shipper) fails to comply with a Company request to alter deliveries or end-use. A shipper is allowed a five percent tolerance between nominations and actual usage. A system imbalance, the Company testifies, can increase gas costs by altering either planned storage operation or planned gas supply acquisition. The Committee contends that transportation customers rely on balancing services, the cost of which is borne by sales customers, and even manipulate balancing service to economic advantage by packing Company storage facilities when market prices for gas are low and taking gas from those facilities when prices are high. The Committee testifies that shippers should bear an allocated share, amounting to \$725,000, of gas balancing expense, which should be recovered at a rate of \$0.02 per Dth for telemetered volumes and \$0.06 per Dth for non-telemetered volumes.

The Company opposes this but offers its own response to the problem in the form of a proposal for a non-discretionary penalty the greater of \$1.00 per Dth or the difference between the first-of-the-month index and the daily index, plus \$0.25 per Dth. The penalty would apply to a shipper's over- or under-delivery that contributes to a system imbalance during a period when the Company has notified it to alter use or deliveries. In the Company's opinion, this proposal would remove the incentive for over- or under-delivery and would link penalties to the increased gas costs caused by it. The Company proposal, as altered in settlement negotiation, is included in, and supported by parties to, the Allocation and Rate Design Stipulation. The Division takes no position on the issue but supports the proposal in the Stipulation. IMGA requests, without opposition, that the Stipulation proposal, if adopted by the

Commission, also apply to the MT tariff.

The Committee identifies balancing services as "no-notice" transportation plus storage provided by the Company to both transportation and sales customers to eliminate differences between delivery volumes and actual use. The Committee believes the penalties proposed by the Stipulation will be insufficient to discipline the conduct of shippers. In addition, it states that the proposal does not adhere to the ratemaking principles of cost-causation and equity.

The large customers, LCG and IGU, oppose such an allocation of costs and characterize the Committee proposal as an attempt to shift cost responsibility from sales to transportation customers. They assert that the Committee's analysis is flawed and urge that no credence be given to it. In the Company's view, the proposal would impose an unjustified cost on each transportation customer, whether or not responsible for imbalances and whether or not the imbalance causes operational problems or increases gas cost. The Company also warns that adoption of the Committee proposal could lead transportation customers to claim an entitlement to no-notice transportation and storage. That, the Company states, would be an intolerable result. The Company also asserts that the proposal could encourage customers to bypass the QGC system. In contrast, the Company believes its proposal would assign penalties only to customers which cause operational problems or increase gas costs.

The Committee properly responds to a problem with the existing tariff and its implementation. Cross-examination of its witness, however, raises questions about the analysis which underlies its proposal that we believe have not been answered. For example, the Company, LCG and IGU state that the proposal, if adopted, may be the basis for customer claims for upstream no-notice transportation and storage. The Company states that it contracts for and requires all of these facilities-based services and the loss of some portion of them could cause serious operational problems. We are not comfortable, therefore, imposing that solution, even though we agree with the Committee that a solution should meet important ratemaking objectives. We will accept the proposal contained in the Allocation and Rate Design Stipulation, and find that it addresses the problem in a reasonable and fair way. It removes a problem with the prior tariff, the element of discretionary application. If, as the Committee suggests may be the case, the penalties are insufficient to alter shipper behavior, or if the

Company fails to enforce them, the subject can be revisited in an appropriate proceeding. We charge the Division to monitor the new situation, and to report to us if inadequacies of this or any other kind are found.

6. Transportation Administrative Charge

LCG and IMGA recommend removing account administration marketing costs of $291,546 from the administrative charge assessed to transportation customers, resulting in a charge of $4,986, and $1,870 for multiple delivery points. The current annual charge is $8,000 per account, and $3,000 for additional accounts served by the same gas supply contract. IGU supports an LCG and IMGA proposal to permit transportation customers to form cooperative organizations so administrative charges would apply to one entity rather than to individual customers.

The Company is opposed to reducing this charge, arguing that it covers the fixed costs incurred to track transportation customers' nominations, gas usage, imbalances and contracts. These customers provide their own gas to the system, and unlike sales customers who are accounted for on a combined basis, each is tracked separately and daily. Because these factors for each customer must be tracked, the proposal to form cooperative organizations would not reduce costs. These costs are fixed; they do not vary with volume, and therefore should be recovered in a fixed charge. The charge covers the labor and overhead for the Altra Systems (receives and processes transportation customers' daily nominations), billing, telemetering, and account administration (five full-time employees who work as account representatives and supervisors, and in gas control and information technology).

Intervenors object to account administration, also termed "industrial marketing" costs. The Company presents a study of employee duties and hours which shows account administrative cost to be $307,743 rather than the $292,000 used to set the current charge. No increase is recommended, however. Because this dispute concerns intra-class revenue requirement, the Company also points out that lowering the administrative fee would result in a reduced fixed charge and an increased volumetric rate.

The Division takes no position on this issue but believes the evidence supports the Company's position. The Committee is concerned that, should the Commission reduce the administrative charge, the resulting revenue loss should not shift to another class of customers. It states that the Company and industrial intervenors agree that it is and will remain an intra-class issue.

LCG argues that the administrative charge lacks adequate support. It terms the Company's testimony "subjective opinion" that is "without sustainable basis." In particular, it believes the industrial marketing cost portion is not justified and should be removed. Doing so, it states, would reduce the $8000 charge to $4986 and the charge for additional end-use sites from $3000 to $1870. LCG states that the administrative charge was adopted as part of a settlement with the objective of discouraging small customers from using transportation service when that service was first made available. In its view, the charge now serves no useful purpose. LCG points out that the Company refuses to apply the $3000 charge to the end-use points of the Industrial Gas Resources Corporation, a non-profit gas purchasing cooperative. LCG asks the Commission to require the Company to extend the lower incremental charge to this entity, which through aggregation of loads allows for a single bill and point of contact. This, it asserts, the Company has done for the state of Utah and others, opening QGC to a charge of discriminatory treatment.

IMGA asserts that a thorough review of the administrative charge is needed to assure that it is cost-justified. It challenges the industrial marketing portion of the costs and argues that the Company fails to meet its burden to provide substantial evidence supporting them. For this reason, the charge should be reduced by approximately 40 percent. IMGA states that it is a governmental entity created under Utah law so its members should qualify for the reduced incremental rate as do other state agencies.

The study of account administrative costs presented by the Company is not rebutted. Intervenors call for detailed review of it, but that has not been done and is not on this record. The Company opposes the LCG proposal to aggregate transportation customers into cooperative organizations on grounds that doing so would not simplify or reduce the costs of tracking each customer daily. Thus to permit aggregation would merely shift costs within the class, it states. We accept this reasoning. We conclude the Company has adequately supported the administrative charge and therefore reject the intervenors' requests to reduce it.

As IMGA acknowledges, no customers yet take service pursuant to the MT tariff. It would be premature to act on IMGA's recommendations, for, as the Company testifies, without customers there is no cost-incurrence experience upon which to base conclusions. IMGA, however, is a governmental agency which acts on behalf of its members. It provides a single voice and a single contact for scheduling and transportation issues, and it owns the pipeline to which QGC delivers gas. The Company agrees that, as with the state of Utah, IMGA should pay a single administrative charge, and if additional IMGA members take delivery at other points on the QPC pipeline, they will pay the $3000 administrative charge. We so order.

7. Western Electrochemical Company (WECCO)

WECCO, an interruptible transportation customer, funded construction of a 13-mile pipeline to connect its facilities with the QGC system. Under terms of the tariff, an interruptible customer is required to make contributions for additional facilities needed to serve it. Pursuant to the main extension agreement between WECCO and the Company, a pipeline large enough to serve anticipated demand in the area was built. The Company bore the incremental cost of the pipe size that exceeded the WECCO requirement. Shortly thereafter, QGC constructed an 8-mile segment connecting the WECCO site with Kern River Pipeline. The entire 21-mile pipeline is now used to serve both WECCO and other customers in the area. WECCO asserts that the eastern portion of the line is used primarily to serve these other customers thus entitling it to special tariff treatment as a quid pro quo for its contribution to funding that portion of the line.

The Company responds that during the test year the WECCO tap on Kern River was closed for 250 days because WECCO's demand alone is insufficient to operate the tap. Contrary to WECCO's representation, the gas it requires flows to it on the eastern segment of the line. In addition, the Company states that all interruptible customers must make contributions in aid of construction of additional facilities needed to serve them and that such contributions do not result in ownership or other rights to portions of the QGC system. These customers receive service under terms of the applicable tariff. The Division agrees that WECCO is treated in this respect in accordance with Company policy, just as are other interruptible customers. The Division asserts that construction of the line to Kern River now provides WECCO the benefit of service without interruption when capacity is not available on QGC's southern system. WECCO, the Division testifies, has no claim for special treatment.

The record shows that WECCO is neither unique nor are special tariff terms required to provide reasonable and nondiscriminatory service to it. Its request for such terms is rejected.

IV. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. Questar Gas Company to file appropriate tariff revisions increasing Utah jurisdictional revenues by $13,497,197, recognizing current interim rates recover $7,065,000 of that amount.

2. The tariff revisions shall reflect the Commission's determinations regarding rate increases, charges and other rate design aspects for service schedules and other changes in rates, fees or charges designated and discussed in the Report and Order. The Division of Public Utilities shall review the tariff revisions for compliance with this Report and Order. The tariff revisions may become effective as designated by Questar Gas Company, but not earlier than the date of this order.

3. The Low Income Weatherization program discussed and approved by this Report and Order shall be implemented beginning with the effective date of the tariff revisions. Questar Gas Company and the Division of Pubic Utilities shall monitor the operations of the program. The Division of Public Utilities shall audit the program as it determines necessary or as directed by the Commission. Questar Gas Company, the Division of Public Utilities and other interested parties may submit requests to modify the program as experience with the program is obtained or otherwise warranted.

4. To the extent the Commission has omitted from the ordering provisions of this Order any duty or obligation intended to be imposed, which duty or obligation is otherwise clear from the language of this Report and Order, it is hereby incorporated herein by this reference and made a part hereof.

This Report and Order constitutes final agency action on Questar Gas Company's December 16, 1999, Application. Pursuant to U.C.A. §63-46b-13, and aggrieved party may file, within 20 days after the date of this Report and Order, a written request for rehearing or reconsideration by the Commission. Pursuant to U.C.A. §54-7-12, failure to file such a request precludes judicial review of this Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §§63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 11th day of August, 2000.

/s/ Constance B. White, Commissioner

/s/ Clark D. Jones, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

DISSENT AND COMMENT OF CHAIRMAN STEPHEN F. MECHAM

I concur with my colleagues in all respects expect for one, the adoption of the CO_2 plant stipulation. The CO_2 gas processing plant issue turns on what the Federal Energy Regulatory Commission (FERC) would have done had Questar Gas first taken the case there. The dispute over the plant never would have arisen had that occurred. In my opinion, that is what the Company should have done. We have been left with too many questions the answers for which we can only surmise.

There are FERC precedents on the record in this case in which gas producers were required to process their gas to meet quality specifications of gas pipelines. Those decisions were available to the Company in 1996 when they began taking coal seam gas. Though I do not disregard the issue of safety, it seems there was ample time to get a definitive answer from the FERC on who should bear the costs of processing the gas without ever jeopardizing customer safety. Questar Gas believes that at most the FERC would have required producers to reduce the maximum percentage of carbon dioxide in the coal seam gas from 3 percent to 2 percent as they did in the two precedent cases and that would not have met Questar Gas's requirements. That is one of the justifications for the compromise in the stipulation the Company and the Division put forward. The parties to the stipulation believe, therefore, that Questar Gas still would have incurred the costs of reducing the maximum percentage of carbon dioxide in the gas from
2 percent to 1 percent. The difficulty is that the facts of Questar's case never went before the FERC so the parties' positions are speculative. It is just as conceivable that the FERC would have required producers to meet Questar Gas's needs. Paragraph 13.5 of Questar Pipeline's tariff gives Questar Gas

leverage to press for that outcome.

It also troubles me that, according to Division witness Dr. Charles Olson in Docket No. 98-057-12, Questar Gas will be the only gas distribution company directly bearing the costs of processing gas. The issue should have gone to the FERC several years ago. Nevertheless, I do not believe it would be fair to simply deny the Company recovery of the CO_2 plant expenses. That decision would be based on speculation as well. Had my view prevailed, the Commission would have declared rates interim subject to refund on the condition that the CO_2 processing plant case be taken to the FERC. That would have held all parties harmless pending the outcome and put an end to the needless conjecture.

Insofar as the weatherization program is concerned, I make a comment but do not dissent. In many respects my position is similar to the one I took in Docket No. 99-035-10 on the Lifeline rate. Utah Code Annotated Section 54-3-1 authorizes the Commission to set rates that encourage conservation of resources. While I believe the state's weatherization program has merit, I am still reluctant to laden utility rates with the costs of a program the legislature has only minimally funded. Nevertheless, unlike the lifeline program, weatherization can be justified on safety grounds. Customers who otherwise might not have their furnaces checked for proper ventilation and operation should have fewer concerns about doing so with the aid of this program. As a result, I do not dissent on this issue but discourage efforts to extend the program beyond that recommended in this case.

/s/ Stephen F. Mecham, Chairman

APPENDICES

1. Summary of Adjusted Distribution Non-Gas Results of Operations ($000).

2. Joint Stipulation Revenue Requirement Issues, Filed June 2, 2000.

3. CO_2 Stipulation, Filed June 2, 2000.

4. Allocation and Rate Design Stipulation, Filed June 5, 2000.

APPENDIX 1.

Summary of Adjusted Distribution Non-Gas Results of Operations ($000)

	1. System Unadjusted Test Year	2. Total System Adjustments	3. System Adjusted Test Year	4. Allocation to Utah	5. Utah Distribution Non-Gas	6. Change in DNG Revenue	7. Final DNG Results
Total Revenue	449,937	55,208	505,144	484,681	196,461	**13,497**	209,959
Gas Purchases	257,265	55,840	313,105	300,667	12,446	0	12,446
Production	(555)	0	(555)	(532)	(532)	0	(532)
Distribution	39,765	479	40,244	38,009	38,009	0	38,009
Customer Accounts	16,243	(896)	15,347	14,655	14,655	0	14,655
Customer Service & Info	3,818	(360)	3,458	3,471	3,471	0	3,471
Administrative & General	44,037	(1,546)	42,491	40,745	40,745	0	40,745
Depreciation	36,365	(1,637)	34,728	33,689	33,689	0	33,689
Amortization	61	0	61	59	59	0	59
Non-Income Taxes	7,625	1,401	9,026	8,843	8,843	0	8,843
Income Taxes	8,643	1,745	10,388	9,865	9,865	5,132	14,998
Total Expenses	413,267	55,026	468,293	449,471	161,251	5,132	166,383
Total Income	**36,670**	**182**	**36,851**	**35,210**	**35,210**	**8,365**	**43,575**
Gas Plant in Service	903,378	(8,624)	894,754	857,365	857,365	0	857,365
Plant Held for Future Use	587	0	587	587	587	0	587
Unclassified Construction	35,976	0	35,976	35,106	35,106	0	35,106
Materials & Supplies	4,170	0	4,170	4,169	4,169	0	4,169
Gas Stored Underground	14,016	(14,016)	0	0	0	0	0
Prepayments	2,486	(1,092)	1,394	1,337	1,337	0	1,337
Cash Working Capital	119	18	137	131	131	0	131
Add'ns to Rate Base	960,732	(23,714)	937,018	898,694	898,694	0	898,694
Accum. Depreciation	392,450	(4,146)	388,304	372,717	372,717	0	372,717
Accum. Depletion & Amort	8,506	(352)	8,154	7,819	7,819	0	7,819
Customer Deposits	2,552	0	2,552	2,444	2,444	0	2,444
Deferred ITCs	5,821	0	5,821	5,484	5,484	0	5,484
Accum. Deferred Inc. Taxes	70,259	0	70,259	66,609	66,609	0	66,609
Ded'ns to Rate Base	479,587	(4,498)	475,090	455,073	455,073	0	455,073
Total Rate Base	**481,144**	**(19,216)**	**461,928**	**443,621**	**443,621**	**0**	**443,621**
ROR on Rate Base	**7.62%**		**7.98%**	**7.94%**	**7.94%**		**9.82%**
ROR on Common Equity	**7.00%**		**7.65%**	**7.57%**	**7.57%**		**11.00%**

APPENDIX 2.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY FOR A GENERAL INCREASE IN RATES AND CHARGES	)))))	DOCKET NO. 99-057-20 **JOINT STIPULATION ON REVENUE REQUIREMENT ISSUES**

Pursuant to Utah Administrative Code § R746-100-10.F.5 and Utah Code Ann. §§ 54-4-1 and 54-4-4 (1994), Questar Gas Company (Questar Gas), the Division of Public Utilities (Division), and the Committee of Consumer Services (Committee) (collectively, "The Parties") submit this Joint Stipulation in resolution and settlement of revenue requirement issues addressed in this proceeding, except for four contested issues described in paragraph 12 of this Stipulation. This Stipulation does not address any issues involving cost allocation among rate classes or rate design.

PROCEDURAL HISTORY

1. On December 17, 1999, Questar Gas filed an application with the Public Service Commission of Utah (Commission) seeking an increase in its Utah rates in the annualized amount of $22,227,000,[1] based on a 1999 calendar test year. The original filing was based on the ten months of actual data (January-October 1999) and two months of projected data (November-December 1999).

[1]Unless otherwise specified, the revenue, cost and rate-base values are the allocations to Utah

operations, as determined by well-established methodologies that are uncontested in this proceeding.

2. On January 11, 2000, the Commission held a prehearing conference at which the parties agreed to a procedural schedule that was approved by the Commission's February 1, 2000, Scheduling Order.

3. Pursuant to the Scheduling Order, on February 18, 2000, Questar Gas filed updated information to replace projected test-period data with actual data for November and December 1999. This filing included revised exhibits detailing an annual revenue deficiency of $22,473,000, based on actual 1999 data. This included test-year revenues of $195,283,000 expenses of 171,741,000 return on equity of 12.0% and a proposed overall return of 10.36% applied to a rate base of $444,165,000. Included in the revenue requirement was an annual recovery of $7,343,000 for the costs incurred by Questar Gas to procure gas-processing services for the removal of carbon dioxide (CO_2) from certain gas supplies delivered to Questar Gas's system.

4. On April 19, 2000, the Division submitted its direct testimony and exhibits, with a calculated revenue deficiency of $10,300,000. The Division proposed test-period revenues of $206,673,000, operating expenses of $163,288,000, and a total average rate base of $441,692,000. The Division recommended a return on equity of 11.0% and an overall return to be applied to the rate base of 9.82%. The Division proposed an allowed annual recovery of CO_2 gas-processing costs of $3,670,000.

5. On April 19, 2000, the Committee also filed its direct testimony and exhibits, with a proposed annual revenue deficiency of $1,781,000. This was calculated from test-year revenues of $196,577,000 operating expenses of $144,565,000, 11.0% return on common equity and an overall rate of return of 9.55% to be applied on an average rate base of $422,309,000. The Committee

proposed that the Commission deny recovery of all CO_2 gas-processing costs.

6. Attached as part of this Stipulation, Exhibit 1 lists in summary form all revenue-requirement issues that have been raised in this proceeding, organized as follows:

I. Uncontested Issues - Group I. These are issues on which the Parties had reached accord prior to the comprehensive agreement of contested issues that forms the basis of this Stipulation. These issues would not have been contested upon final submission to the Commission, even in the absence of this Stipulation.

II. Issues Settled by Joint Stipulation - Group II. The Parties have not been able to reach an issue-by-issue agreement for the items included in Group II. For the purposes of reaching a comprehensive settlement of all issues except those in the contested-issue Group III below, the Parties have concurred on the aggregate effect that an overall resolution of these issues is to have on Questar Gas's test-year revenue deficiency.

III. Contested Issues - Group III. Among the three Parties, there has been no concurrence on the four issues listed in this category: rate of return on common equity; capital structure; allocation of billing-postage costs; recovery of costs of procuring CO_2 gas-processing services. The CO_2 gas-processing issues are the subject of a separate stipulation between Questar Gas and the Division to which the Committee is not a party.

7. Thus, except for the issues in Group III on Exhibit 1, in settlement of the positions of the Parties on issues that affect the test-year revenue requirement, the Parties have reached a full and final resolution of all other revenue-requirement issues in this case and submit for the Commission's approval

the terms and conditions of this Stipulation.

SETTLED ISSUES

8. On or about May 18, 2000, during settlement discussions among the Parties, the three Parties agreed to several adjustments that had the net effect of reducing the Company's calculation of the annual Utah revenue deficiency to $21,711,000. The same adjustments served to change the Division's and Committee's Utah revenue deficiencies to $10,261,000 and $5,766,000, respectively. These adjustments are summarized under the heading "Uncontested Issues - Group I" of Exhibit 1.

9. The net effect of the comprehensive settlement of contested issues designated II(a) through II(s) on Exhibit 1 is to reduce further Questar Gas's position on the annual Utah revenue deficiency, as stated in paragraph 8, by $1,550,000 to $20,161,000. Correspondingly, the positions of the Division and the Committee have been increased to $11,458,000 and $7,202,000, respectively. (These values do not reflect the Questar

Gas-Division Stipulation on CO_2 costs.)

10. When the Questar Gas-Division Stipulation on CO_2 issues is incorporated, the overall result of the full settlement of all uncontested and contested issues in Groups I and II on Exhibit 1 is to reduce Questar Gas's position on the annual Utah revenue deficiency to $17,818,000. The corresponding positions of the Division has been increased to $12,785,000, and the Committee's position is $7,202,000. The differences among these three revenue-deficiency positions are attributable to the differences among the Parties with respect to contested, Group III issues on Exhibit 1.

11. With respect to the research and development issues (Issue II(r), Exhibit 1), the Parties agree that Questar Gas may utilize its pass-through cases at year-end 2000, 2001, 2002 and 2003 to

transfer from the commodity portion of rates to the distributor non-gas (DNG) portion of rates an amount equal to the reduction in the FERC-approved Gas Research Institute (GRI) surcharge. The parties agree to support this procedure and agree that Questar Gas should generally be allowed to invest in R&D programs at a level of expense similar to what has been historically included in FERC-approved rates as the GRI surcharge. Questar Gas agrees to provide information on the R&D projects it supports and agrees that any Party can challenge Questar Gas's contribution to any particular project in appropriate proceedings. Questar Gas has agreed to contribute to R&D projects undertaken by organizations such as GRI that are designed and expected to benefit natural gas LDC's customers.

CONTESTED ISSUES

12. The Parties have not reached unanimous agreement on the CO_2 processing costs, the postage-expense issue, the equity-return issue (and the associated capital-structure issue).

13. As reflected in a separate settlement agreement, Questar Gas and the Division have reached a bilateral agreement on the CO_2 issue.

GENERAL TERMS AND CONDITIONS

14. For the revenue, rate base, and expense items covered in this Stipulation, it represents a settlement by all parties who have raised or taken a position on these items in this docket.

15. All negotiations related to this Stipulation are privileged, and except for the issue set forth in paragraph 11, no Party shall be bound by any position asserted in negotiations. Neither the execution of this Stipulation nor the order adopting this Stipulation shall be deemed to constitute an acknowledgment by any party of the validity or invalidity of any principle or practice of ratemaking; nor shall they be construed to constitute the basis of an estoppel or waiver by any Party; nor shall they be

introduced or used as evidence for any other purpose in a future proceeding by any party to this Stipulation.

16. The Parties believe that settlement of these issues through this Stipulation is in the public interest and that the rates, terms and conditions it provides for are just and reasonable.

17. Each of the Parties and any other parties to the proceeding may present evidence to explain and support this Stipulation. Any such witnesses will be available for examination.

18. This Stipulation shall remain in effect from the date of the Commission's order approving the Stipulation until the date of a superseding Commission order.

19. This Stipulation is an integrated whole, and any Party may withdraw from it if this Stipulation is not approved in its entirety by the Commission.

APPENDIX 3.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY FOR A GENERAL INCREASE IN RATES AND CHARGES	)))))	DOCKET NO. 99-057-20 **CO_2 STIPULATION**

Pursuant to Utah Administrative Code § R746-100-10.F.5 and Utah Code Ann. §§ 54-4-1 (1994) and 54-4-4 (1994), Questar Gas Company (Questar Gas) and the Division of Public Utilities (Division) submit this Stipulation in resolution and settlement of cost recovery and ratemaking for CO_2 processing contract costs.

PROCEDURAL HISTORY

1. Questar Gas originally applied for cost recovery in its November 25, 1998, Application in Docket No. 98-057-12 for gas processing contract costs paid to Questar Transportation Services Company (QTS). The Application sought authorization to recover an annualized amount of approximately $7.5 million through Questar Gas's 191 Gas Cost Balancing Account.

2. The Division and Committee of Consumer Services (Committee) filed a Motion for Summary Judgment on April 30, 1999, opposing 191 Account recovery of these costs. After denying the Motion, the Commission held hearings on June 22 and 23, 1999, with post-hearing briefs filed on September 1, 1999, and September 30, 1999.

3. On December 3, 1999, the Commission denied recovery of CO_2 gas processing costs in the

191 Gas Cost Balancing Account. The Commission determined that recovery of these costs must be considered either in a general rate case or an abbreviated proceeding.

4. Concurrently with the December 17, 1998, filing of its Application for General Rate Relief and separate Emergency Motion for Interim Relief, Questar Gas requested that the Commission take official notice of the record in Docket No. 98-057-12. The Committee also moved for such official notice on January 11, 2000. Finally, Questar Gas submitted its Motion requesting the Commission to take official notice of the record on Docket No. 98-057-12 on May 23, 2000, which Motion was unopposed by the Division and Committee.

5. On January 11, 2000, Questar Gas, the Division, the Committee of Consumer Services (Committee) and interveners attended a prehearing conference and agreed to a procedural schedule which was announced by the Commission's February 1, 2000, Scheduling Order.

6. On April 19, 2000, the Division, Committee and interveners submitted direct testimony and exhibits, supplementing the Docket 98-057-12 record. Parties submitted rebuttal testimony on May 24, 2000 and surrebuttal testimony on May 31, 2000.

7. In settlement of the revenue requirement issues in this case involving CO_2 processing costs, Questar Gas and the Division submit the terms and conditions of this CO_2 Stipulation for the Commission's approval and order.

8. After considering all of the positions concerning CO_2 processing of each party, this Stipulation has been agreed to in recognition of the requirement of Questar Gas to manage the heat content of the gas entering its system so as to protect the safety and well being of Questar Gas customers. Thus, Questar Gas and the Division agree and stipulate that CO_2 processing contract costs

in the amount of $5 million for the Utah jurisdiction should be included in the revenue requirement in this case.

9. The Division and Questar Gas agree and stipulate that the term of the CO_2 processing agreement between Questar Gas and QTS is to be five years beginning from the date of commencement of processing services in June 1999. During the remaining term of the contract, Questar Gas will retain first rights to CO_2 processing service from the Castle Valley plant but will have no right to any revenue credits for processing performed by QTS for others. At the end of the contract, Questar Gas will have no interest in or claim on the plant. At that time, any additional CO_2 processing needed by Questar Gas will require separate regulatory approval for cost coverage.

10. The Division and Questar Gas agree and stipulate that the processing costs will continue to be based on cost-of-service pricing. In any future rate proceeding using an annual test period with data through June 2004, the maximum annual amount to be included in rates will be $5 million. Actual processing costs up to $5 million will be considered with all other revenues and expenses by the Division in its review of Results of Operations.

11. Questar Gas agrees that the Division will have the right to information on the CO_2 processing costs and can use that information in assessing ongoing earnings levels of Questar Gas.

12. This is a contested Stipulation. As such, neither the Committee nor any intervener in this case has agreed to the recommendations set forth herein.

13. All negotiations related to this Stipulation are privileged and no party shall be bound by any position asserted in negotiations. Neither the execution of this Stipulation nor the order adopting this Stipulation shall be deemed to constitute an acknowledgment by any party of the validity or invalidity of

any principle or practice of ratemaking; nor shall they be construed to constitute the basis of an estoppel or waiver by any party; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any party to this Stipulation. The parties believe that settlement of these issues through this Stipulation is in the public interest and that the rates, terms and conditions in provides for are just and reasonable.

14. Questar Gas and the Division, and any other parties may, present testimony of one or more witnesses to explain and support this Stipulation. Such witnesses will be available for examination.

15. This Stipulation shall remain in effect from the date of the Commission's order approving the Stipulation until the date of a superseding Commission order.

16. This Stipulation is an integrated whole, and any party may withdraw from it if this Stipulation is not approved in its entirety by the Commission.

APPENDIX 4.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY FOR A GENERAL INCREASE IN RATES AND CHARGES	)))))	DOCKET NO. 99-057-20 **ALLOCATION AND RATE DESIGN STIPULATION**

Pursuant to Utah Administrative Code § R746-100-10.F.5 and Utah Code Ann. §§ 54-4-1 (1994) and 54-4-4 (1994), Questar Gas Company (Questar Gas), the Division of Public Utilities (Division), the Large Customer Group (LCG)[1] and the Industrial Gas Users (IGU),[2] (collectively, "the Parties") submit this Stipulation in resolution and settlement of issues of CO_2 recovery and allocation, daily balancing and firm transportation rate design (the "Stipulated Issues").

PROCEDURAL HISTORY

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[1]The companies that make up the LCG group are listed in its Petition to Intervene filed on March 22, 2000.

[2]The companies that make up the IGU group are listed in its Petition to Intervene filed on April 11, 2000.

1. On December 17, 1999, Questar Gas filed an application and direct testimony with the Public Service Commission of Utah (Commission) seeking an increase in its Utah rates in the annualized amount of $22,227,000. This application contained Questar Gas's recommendations regarding CO_2 processing cost recovery and allocation, daily balancing provisions and rate design for all customer classes.

2. On January 11, 2000, the Commission held a prehearing conference at which the parties agreed to a procedural schedule that was approved by the Commission's February 1, 2000, Scheduling Order.

3. On April 19, 2000, the Division and LCG submitted direct testimony and exhibits addressing the Stipulated Issues. Rebuttal testimony was submitted by Questar Gas on May 24, 2000, and surrebuttal testimony by the Division and LCG was submitted on June 1, 2000.

4. On June 2, 2000, the Division and Questar Gas submitted a stipulation in settlement of the revenue requirement issues in this docket involving CO_2 processing costs (the "CO_2 Stipulation").

5. In settlement of the Stipulated Issues in this case, the Parties submit the terms and conditions of this Stipulation for the Commission's approval and order.

FIRM TRANSPORTATION AND RATE DESIGN

6. The Parties agree and stipulate that firm transportation service should be offered as generally described in the rebuttal testimony of Questar Gas witness Barrie L. McKay (Exhibits QGC 6R, 6.1R, 6.2R), and that Questar Gas's Utah Natural Gas Tariff will provide for two firm transportation rate schedules, FT-1 and FT-2.

7. Rate Schedule FT-1 will be a continuation of current FT service and will serve as an anti-bypass rate schedule, designed to retain customers with economic alternative transportation options. Customers will qualify for this rate schedule based on (1) annual usage of at least 100,000 Dth and proximity to the nearest interstate pipeline of five miles or less; or (2) annual usage of at least 4,000,000 Dth. Proceeds from this rate will continue to be treated as a revenue credit in the rate design.

8. Rate Schedule FT-2 will be available to all firm transportation customers who do not qualify under Rate Schedule FT-1. This rate schedule will be allocated a uniform percentage increase of the final revenue deficiency in this proceeding.

CO_2 COST RECOVERY AND ALLOCATION

9. IGU and LCG will not oppose the June 2, 2000, CO_2 Stipulation and agree that the Stipulation is a reasonable resolution of recovery of CO_2 processing costs in Questar Gas's rates and agree and stipulate to the terms and conditions of the June 2, 2000, CO_2 Stipulation.

10. The Parties agree and stipulate that the annual CO_2 processing costs of up to $5 million specified in the CO_2 Stipulation will be allocated to rate classes using the following method, as illustrated on Rate Design Stipulation Exhibit 1:

(a) An initial class allocation of the total cost of service[3] will be determined by spreading the final revenue deficiency, exclusive of the $5 million annual CO_2 cost recovery, by means of a uniform percentage increase (line 1).[4]

(b) This determines a percentage allocation for each class (line 2).

[3]The dollar values on line 1 of Exhibit 1 are hypothetical and used here for illustrative purposes only.

(c) The percentage weights for Rate Schedules IT and FT-2 are doubled (line 3).

(d) The cost allocations of the other classes are reduced on a pro-rata basis to account for the double-weighted allocation to Rate Schedules IT and FT-2 (line 4).

(e) Adding lines 2, 3 and 4 yields the allocation percentages for CO_2 costs by rate schedule (line 5).

(f) Line 6 gives the resulting allocations of the $5 million annual CO_2 cost recovery specified in the CO_2 Stipulation in this proceeding.

DAILY BALANCING

11. The Parties agree and stipulate that the following terms and conditions should be incorporated in Questar Gas's tariff regarding daily balancing.

12. Questar Gas will continue to allow ±5% of a customer's volumes delivered to the city gate as a daily imbalance tolerance "window." In the event a customer's imbalance contributes to an aggregate imbalance that would (1) require Questar Gas to take action to maintain system integrity or (2) reasonably be expected to force the Company to alter materially its prior day's planned level of (a) gas purchases, (b) Company production, or (c) storage injections or withdrawals, then Questar Gas may give notice to and require customer action as set forth in paragraph 14.

13. If conditions exist as described in paragraph 12, Questar Gas may, for the period that such conditions are reasonably expected to continue, require customers or nominating parties to adjust deliveries or usage, and/or to suspend all or a portion of the daily imbalance intolerance window. A

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[4]Except for Rate Schedules NGV-1, NGV-2 and FT-1, which have no costs allocated to them.

customer or nominating party may adjust deliveries by directing a change in nominations, alter usage, or utilize park-and-loan or other services offered by the appropriate upstream pipeline.

14. Questar Gas will provide notice of such restriction to each affected nominating party not less than two hours prior to the first nomination deadline for the affected period or as soon as reasonably practicable, to the extent system integrity or upstream allocations allow. If other than written notice is initially provided, the subsequent written follow-up will provide the time of contact and the person contacted. Restrictions may be applied on a system-wide basis, a nominating-party-by-nominating-party basis, a customer-by-customer basis, or a geographic-area basis, as circumstances reasonably require.

15. Notices of balancing restrictions will be provided to each affected nominating party and will include reasonable specificity regarding:

(a) The duration and nature of the balancing restrictions imposed;

(b) The events or circumstances that require the restrictions;

(c) The type of imbalances that may be subjected to penalties; and

(d) Actions that the customer can take to avoid penalties.

16. If a customer fails to comply with balancing restrictions reasonably imposed by Questar Gas after notice provided in paragraph 14, a balancing penalty of the greater of $1.00/Dth or the difference between the Questar Pipeline first-of-the-month posting in "Inside FERC" and the Questar Pipeline daily posting in "Gas Daily" (or subsequently applicable publications) plus $0.25/Dth will, except under conditions of force majeure, be charged for those imbalances that adversely affect the system.

17. Customers or nominating parties may exchange or aggregate imbalances in order to avoid or mitigate penalties. Penalties that are not totally avoided by exchange or aggregation will be borne by the customer or prorated among the customers as directed by the nominating party. If no direction is received, the Company will assign the imbalance to each of the nominating party's accounts on a pro-rata basis for all such accounts that are contributing to the imbalance that adversely affect the system on the tenth business day following the last day of the notice.

18. Questar Gas reserves the right to take any action necessary to restrict deliveries or usage in order to maintain a balanced distribution system when required to maintain system integrity. A balancing penalty of up to $25.00/Dth may be imposed in cases where a customer has repeatedly ignored, after written notice, Questar Gas's reasonable balancing restrictions. There will be no daily imbalance tolerance during periods of interruption. Attached Rate Design Stipulation Exhibit 2 shows the tariff changes that will implement these provisions.

19. The parties oppose any allocation or charge to transportation customers for NNT or storage services purchased by Questar Gas for its sales customers. The tariff provisions specified above represent a more appropriate, efficient and practical method of insuring that Questar Gas's sales customers receive the intended benefits of Questar Gas's NNT and storage rights.

GENERAL TERMS AND CONDITIONS

20. This is a contested Stipulation. As such, the Committee of Consumer Services and other interveners have not approved or stated positions on this Stipulation.

21. All negotiations related to this Stipulation are privileged, and no Party shall be bound by any position asserted in negotiations. Neither the execution of this Stipulation nor the order adopting

this Stipulation shall be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any principle or practice of ratemaking; nor shall they be construed to constitute the basis of an estoppel or waiver by any party; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any party to this Stipulation. The Parties believe that settlement of these issues through this Stipulation is in the public interest and that the rates, terms and conditions it provides for regarding the Stipulated Issues are just and reasonable.

22. Questar Gas and the Division will, and other Parties may, present testimony of one or more witnesses to explain and support this Stipulation before the Commission. Such witnesses will be available for examination.

23. This Stipulation is an integrated whole, and any Party may withdraw from it if this Stipulation is not approved in its entirety by the Commission.